PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

July 5, 2019 **REVISED** **VIA E-MAIL**

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Toronto, ON

Dear Ms. Walli:

Re: EB-2019-0082 – Hydro One Network 2020 Transmission Revenue Requirement
Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

Please find attached the interrogatories of VECC in the above-noted proceeding. We have also directed a copy of the same to the Applicant.

Yours truly,

M Garner

Mark Garner
Consultants for VECC/PIAC

Ms. Linda Gibbons, Senior Regulatory Coordinator – Regulatory Affairs Hydro One Networks Inc.
regulatory@HydroOne.com

REQUESTOR NAME	**VECC**
TO:	**Hydro One Networks Inc. – Transmission (H1TX)**
DATE:	**July 3, 2019 – Revised July 5**
CASE NO:	**EB-2019-0082**
APPLICATION NAME	**2020-2022 Transmission Rates/UTR Application**

Unless otherwise noted references are to the Updated (June 19, 2019) evidence

1.0 EXHIBIT A - ADMINISTRATION

1.0-VECC-1

Reference: ExA/T2/S4/pg.15

a) What costs (if any) are currently included in H1 TX revenue requirement or rate base for the Niagara Reinforcement project?

b) Given the proposed partnership is it contemplated that the competition of this project will have no effect on the current application (including load forecast)?

1.0-VECC-2

Reference: ExA/T3/S1/Attachment 1 – 2019-2024 Transmission Business Plan

a) Please identify any material changes as between the December 14, 2018 2019-2024 Transmission Business Plan and the EB-2019-0082 Application request. Specifically address the capital renewal plan at pages 9-10 of the plan with the capital budget proposal in this application.

b) Please explain the reason for any identified material changes.

1.0-VECC-3

Reference: ExA/T3/S1/Attachment 1 – 2019-2024 Transmission Business Plan, pgs. 19-

a) For each of the five productivity measures listed in the Business Plan please provide the measure metric for the initiative and the baseline from which it is measured.

1.0-VECC-4

Reference: ExA/T4/S1/pgs.5- & EB-2018-0218 Hydro One Sault Ste. Marie LP, Decision with Reasons, pgs. 19-21.

a) At the Decision reference the Board declined to approve the applied for 0.0% stretch factor. The Board has adopted for this proceeding the record with respect to both the PSE and PEG Reports, the former relied upon the Applicant in this proceeding (Board letter of June 28, 2019).

   Please explain what different factors should be considered in this case which would mitigate, or ague against the application of a 0.3% stretch factor to Hydro One Transmission as the Board has determined should be applied to Hydro One Sault Ste. Marie.

1.0-VECC-5

Reference:

a) A number of the capital projects, including the Horner and Halton TS projects and the Air Blast Circuit Breaker Replacement Project might reasonably be considered under the Board's ACM or ICM policies, in that they are distinct and material. Please explain why Hydro One TX has chosen to use a custom capital factor rather than seek approval under the ACM/ICM for specific projects above a calculated materiality threshold.

b) What would by Hydro One TX's ICM/ACM materiality threshold for 2020?

1.0-VECC-6

Reference: ExA/T4/S1/pg.7- Capital Factor

a) Is Line 13 of Table 2 showing only the forecast inflation rate? If not please explain how line 13 in Table 2 is calculated.

b) For the 2020 to 2022 period (inclusive) and for all items other than the forecast for inflation, does Table 2 contain the actual figures for the calculation? Specifically is line 1 "Rate Base" fixed for the period or is it adjusted each year for actual results?

c) Please explain the difference between line 8 in Table 2 and the Total capital expenditure as shown in Table 2 of Exhibit B-1-1/TSP Section 3.3/page 3 of 20.

1.0-VECC-7

Reference: ExA/T4/S1/pg.7- Capital Factor

a) Please confirm (or correct) that the effect of the capital factor is to provide in rates 100% of the revenue requirement impact of the projected increase in rate base for the rate period?

b) In the case where projected rate base additions vary from the projections shown in Table 2 what is the consequence – that is what adjustments is made to rates in the immediate rate year following the rate base addition variance from forecast?

c) Is the intent of the CISVA to capture rate base addition variances? If yes, then by way of example, please show the equivalency in the impact on revenue requirement in each of the 3 years of the plan for a variation in capital expenditures. For example, show how a 5% shortfall in projected rate base (as shown in Table 2) in each year 2020 to 2022 is captured in the CISVA and the equivalent revenue requirement amount is returned to ratepayers/customers.

1.0-VECC-8

Reference: ExA/T4/S1/pg.10

a) Please explain how the 98% threshold for capturing capital spending lower than forecast was established. For example, why was 95% or 99% not chosen?

b) Please provide the list of productivity initiatives that are potential candidates to be excluded from the end of term disposition of the CISVA. Please also provide the standards, metrics or other mechanisms by which productivity gains are to be determined "verifiable."

c) The CISVA is calculated on a net basis at the end the rate term and would, *prima facie*, provide an incentive to under spend in the early years of the program and overspend in the latter years. Theoretically resulting in no refund to customers even though lower than forecast capital projects were in service in years 1 and 2 of the rate plan. Please explain how this aspect of the CISVA has been considered.

2.0 EXHIBIT B – TRANSMISSION SYSTEM PLAN

2.0-VECC-9

Reference: ExB/T1/S1/TSP Section 1.1/ pg. 32

a) Hydro One has three types of customers: generators, large industrial end users and local distribution companies (LDCs). Did the customer engagement surveys and other activity consider each type of customer separately and with a different set of questions or was one single form of survey used for all three customer groups? For example, was the number of customers concerned with power quality differentiated among the types of customers?
b) Does Hydro One maintain a database of requests and complaints from each of its 153 (or 156) customers?
c) Does Hydro One TX assign account managers for each of its 153/156 customers? Does Hydro One schedule annual, biannual or regular meetings with each of its customers?
d) Does Hydro One Tx hold annual group meetings with LDCs in order to better understand this sectors needs and service issues? If not please explain why this would not be desirable?

2.0-VECC-10

Reference: ExB1/S1/T1/TSP Section 3.3 pg. 8

a) Please provide the project amounts approved by the Board I EB-2013-0416 and EB-2014-0140 for the Backup Control Centre.
b) Please provide the business plan revision which shows the reasons for not proceeding with the original Backup Control Centre.
c) Please explain how the budget amounts allocated for the original control center project get spent, or explain how the absence of this project resulted in a savings to rate base during the prior rate period.

2.0-VECC-11

Reference: ExB/T1/S3/Appendix 2-AA

a) Please explain the methodology used to estimate the number and cost of load and generator customer connections for 2019 and 2020.

3.0 EXHIBIT C – RATE BASE

3.0-VECC-12

Reference: ExC/T2/S1/pg.2/Table 1

a) Please provide a summary of Table 1 (In-Service Capital Additions 2014-2022) which shows the period totals for plan and actuals for each capital category and also includes the total capital contributions planned and actual. Please also provide the percentage of capital contributions attributable to the different capital categories (System Access/System Renewal/System Service/General Plant)

3.0- VECC-13

Reference: ExC/T2/S1/Attachment 1/pg.24 & 42 (EB-2014-0160 Exhibit B1, Tab 3, Schedule 2-)

a) Using the categories and format of Table 5 (2017) and Table 20 (2018) please provide a table showing the actual 2014 through 2018 actuals amounts. For 2017 and 2018 please also show the EB-2014-060 proposed and DRO adjusted amounts).

4.0 EXHIBIT D – SERVICE QUALITY AND RELIABILITY REPORTING

4.0 –VECC -14

Reference: ExD/T2/S1/Attachment 1, pg. 3

a) Please explain the rationale for different customer delivery point performance standards based on load size. If the response relies on requirements in the Transmission System Code, please provide those requirements.

b) The proposed standards are based on data which is between 28 and 19 years old. Please explain why standards based on this aged data remain relevant to current performance of delivery points in Ontario.

c) Please explain the impediments to updating the standards based on 2000-2018 data.

d) Please explain for each of the past 5 years (2019 inclusive) how many "technical and financial evaluations were done in consultation with affected customers" due to point performance failing below the minimum CDPP.

4.0 –VECC -15

Reference: ExD/T2/S1/Attachment 1, Section 2.1.4

a) In the above noted section is an explanation as to the attribution of costs for delivery point reliability improvements. Please clarify – if a delivery points falls below the CDPP standard can the affected customer(s) be required to financially contribute to improvements to bring the delivery point to its respective CDPP standard. If this is correct please explain the rationale for customer contribution to maintain a station at its CDPP standard.

5.0 EXHIBIT E – OPERATING REVENUES

EXTERNAL REVENUES

5.0-VECC-16

Reference: Updated Exhibit E/T1/S1, page 1

a) Please provide a schedule that sets out the External And Other Revenues for 2015-2020 broken down as between: External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit.

5.0-VECC-17

Reference: Updated Exhibit E/T2/S1, page 2 (Table 1)

a) Please provide a schedule that sets out the forecast/approved External Revenues (broken down per Table 1) for:
   - 2015 and 2016 per EB-2014-1040
   - 2017 and 2018 per EB-2016-0160
   - 2019 per EB-2018-0130.

5.0-VECC-18

Reference: Updated Exhibit E/T2/S1, pages 1 and 2

Preamble: The Application states (page 1): "The costing of external work is determined on the basis of cost causality, with estimates calculated in the same way as internal work estimates, using the standard labour rates, equipment rates, material surcharge, and overhead rates. An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit for the transmission ratepayers".

a) Please provide a schedule that for each of the years 2017-2022 sets out the "margin" (i.e. the revenues in excess costs) included in each category of External Revenues in Tables 1 and 2.

5.0-VECC-19

Reference: Updated Exhibit E/T2/S1, pages 3-4

a) Please provide a schedule that for each of the years 2015-2018 sets out the revenues from "unbudgeted one-time transactions involving easement grants (e.g. water mains) and operational land salves (e.g. roadways)".

b) Given that revenues from unbudgeted one-time transactions have occurred every year, why would it not be reasonable to include an allowance for such revenues in the determination of the External Revenues to be used for rate setting purposes for 2020-2022?

5.0-VECC-20

Reference: Updated Exhibit E/T2/S1, pages 2 and 6

a) For each of the years 2015-2019 how much of the Other External Revenues (per Table 1) is attributable to the leasing of idle transmission lines?

b) Please explain each of the following variances:
   i. The forecast decrease ($2.1 M) in Other External Revenues in 2018 relative to 2017.
   ii. The forecast increase ($1.1 M) in Other External Revenues in 2021 relative to 2020.
   iii. The forecast decrease ($0.9 M) in Other External Revenues in 2022 relative to 2021.

5.0-VECC-21

Reference: Updated Exhibit E/T2/S1

a) It is noted that there is no External Revenue related to interest income. Is there no interest income associated with Hydro One Networks Transmission business?

b) If there is no interest income, please explain why?

c) If there is interest income, please indicate where it is accounted for the determination of the revenue requirement.

LOAD FORECAST

5.0-VECC-22

Reference: Exhibit E/T3/S1, pages 1 and 4
Exhibit A – Cover Letter

Preamble: The Application states (page 1) that the load forecast was prepared in December 2018. The Application also states (page 4) that the load forecast took into account actual 2018 load.

a) Given the timing of the preparation of the load forecast, what actual data for 2018 was available and used in the preparation of the forecast? In the response please address:
   i. For what period were values for actual Ontario electricity demand available and used?
   ii. For what period were actual values for CDM savings available and used?
   iii. For what period were actual values for the inputs used into the various load forecast models available and used?

5.0-VECC-23

Reference: Exhibit E/T3/S1, pages 5-6

a) Please indicate the sources used for the Provincial Population and Commercial Floor Space forecasts and when the source forecasts were prepared.

5.0-VECC-24

Reference: Exhibit E/T3/S1, page 1 and pages 7-8

Preamble: The Application states (page 1) that "Hydro One worked with the Independent Electricity System Operator ("IESO") and used their latest CDM assumptions in preparing the load forecast in this rate application."

The Application further states (page 7) that "Hydro One has taken into account all the latest IESO's province-wide conservation forecast and used a similar methodology to incorporate these CDM impacts into the load forecast."

The Application also states (page 8) that "Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2022. These CDM peak impacts are consistent with the 2013 LTEP and the latest figures from IESO".

a) Please provide schedules that set out the actual/forecast cumulative CDM demand (system peak load) and energy savings per the OPA's 2013 LTEP for the period 2006 to 2022 (per page 7, lines 10-12). As part of the response, please indicate which for which years the values were actual vs forecast.

b) The Application states (page 7, lines 12-14) that the Ontario Planning Outlook (OPO) provided by the IESO in 2016 did not introduce new CDM figures for peak load.

   i. Did the OPO introduce new CDM figures for energy for the actual/forecast years in the 2013 LTEP? If so, please provide a schedule that sets out these "new" values for the period 2006 to 2022 and contrast them with values from the 2013 LTEP.

   ii. In the 2016 OPO did the IESO adopt and use the CDM values for peak load as presented in the 2013 LTEP or did the IESO not address or indicate its expectations regarding future CDM savings for peak load?

c) The Application states (page 7, lines 16-18) that "In October 2017, the Ministry of Energy released an update to the Long-Term Energy Plan, which did not provide updated figures for peak CDM relating to conservation programs".
   i. Did the Ministry's update include updated (relative those presented in the 2013 LTEP and 2016 OPO) new actual/forecast values for energy CDM?
   ii. If yes, please provide a schedule that sets out these "new" values for the years 2006 to 2022 and contrasts them with values from the 2013 LTEP and the 2016 OPO.

d) The Application states (page 7, lines 18-20) that "Hydro One has taken into account all the latest IESO's province-wide conservation forecast and used a similar methodology to incorporate these CDM impacts into the load forecast." Please clarify what Hydro One means by "all the latest IESO's province-wide conservation forecast" in terms of which forecast is Hydro One referring to (i.e. is it one of those referenced in lines 10-20 or a more recent forecast) and provide a copy/reference to the referenced IESO forecast.

e) The Application states (page 7, lines 19-20) that Hydro One has "used a similar methodology to incorporate these CDM impacts into the load forecast". Please clarify by what is meant by a similar methodology – to what is Hydro One's methodology "similar"?

f) The Application states (page 7, lines 22-24) that "details of the latest information that was provided in March 2018 by the IESO and the methodology used by Hydro One to derive the CDM impacts for the three charge determinants have been documented as part of this Application".
   i. Please describe precisely what information was provided by the

IESO in March 2018.

ii. Where is this information documented in the current Application?

iii. Please provide a copy of the actual information provided by the IESO and any associated correspondence.

g) The Application states (page 8, lines 1-3) that "Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2022. These CDM peak impacts are consistent with the 2013 LTEP and the latest figures from IESO".

i. Is the reference to the "lasted figures from the IESO" referring to the information provided in March 2018?

ii. If not, what is the reference to the "latest figures from the IESO" referring to? Also, please provide a copy.

h) The Application states (page 8, lines 1-3) that "Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2022. These CDM peak impacts are consistent with the 2013 LTEP and the latest figures from IESO".

i. Please provide schedules that set out the CDM peak impacts for 2006 to 2022 (cumulative from 2006): a) per the 2013 LTEP and b) based on the "latest figures from the IESO".

ii. If the two sets of values per point (i) are not the same, please explain how "These CDM peak impacts are consistent with the 2013 LTEP and the latest figures from IESO".

iii. If the actual results to date since the 2013 LTEP as set out in Table 2 are the same as those forecast in the 2013 LTEP, please explain whether this is because: a) the actual results to date (as verified by the IESO) regarding the impact of CDM are equivalent to those forecast by the OPA in the 2013 LTEP or b) the IESO's latest figures have assumed that actual results to-date are equal to those set out in the 2013 LTEP.

iv. If the forecast values in Table 2 are the same as those in the 2013 LTEP, please explain whether this is because: a) the IESO has not updated its forecast since the 2013 LTEP or b) the latest forecast provided by the IESO has confirmed that the 2013 LTEP forecast was still valid.

v. If the actual results to date since the 2013 LTEP as set out in Table 2 are the same as those forecast in the 2013 LTEP please explain why the results have not been updated to reflect the verified results for 2013 and 2014 as discussed in Exhibit H, Tab 1, Schedule1, page 9 and used for purposes of the CDM variance account.

5.0-VECC-25

Reference: Exhibit E/T3/S1, pages 7 and 8

a) With respect to Table 2, please indicate which years represent actual data and which are based on forecast data.

b) Were all of the values related to the impact of CDM on “Peak Demand” based on information from the IESO?

c) For years where the CDM impacts on Peak Demand were not provided directly by the IESO, how were they determined?

d) For years where the CDM impacts on Peak Demand were provided directly by the IESO please provide a reference to (i.e., web link) or copy of the IESO source documents.

e) Were the values for the Cumulative CDM Impact on 12-month Average Peak Demand also provided by the IESO? If not, how were they determined and was the same approach used for both actual and forecast values?

f) Please provide a breakdown of the values provided in Table 2 as between the two CDM categories (energy efficiency programs and codes & standards) – per page 7 (lines 20-22).

g) Please confirm that the CDM savings set out in Table 2 do not include any savings from demand response (or similar) programs. If not confirmed, please provide a schedule setting out the amounts included.

h) Please confirm that the CDM savings set out in Table 2 are represent the expected savings for each year and not “annualized savings” based on the assumption that all CDM programs are implemented January 1st.

5.0-VECC-26

Reference: Exhibit E/T3/S1, pages 1, 9 and 19-21

Preamble: The Application states (page 9) that “the forecast growth rates are applied the normalized base year”.
The Application states (page 19) that “the 12-month average charge determinant forecasts grow from 2018 at the same rate as the 12-month average peak for Ontario”.
The Application also states (page 21) that “before adjusting for the load impacts arising from embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 22,159 MW in 2018” (emphasis added).

a) What was the “base year” to which the forecast growth rates were applied?

b) If the base year is 2018 (as suggested on page 19) were the growth rates applied to the actual 2018 charge determinants or forecast values of the 2018 charge determinants?
   i. If applied to the actual value please explain how this was the case as the load forecast was prepared in December 2018 (per page 1).
   ii. If applied to the actual value please explain the reference on page 21 to the 2018 value being a forecast.
   iii. If applied to a forecast value for 2018 please provide a schedule that compares the forecast values used (for Ontario Peak Demand,

Ontario Demand – 12 month average peak, and each of the three charge determinants) with the actual values for 2018.

5.0-VECC-27

Reference: Exhibit E/T3/S1, pages 15-19

Preamble: The Application states (page 19) that "the 12-month average charge determinant forecasts grow from 2018 at the same rate as the 12-month average peak for Ontario".

a) For each of the models used, please indicate whether the model provides a forecast of each of the 12 monthly peaks. If not, please indicate what "peak(s)" the model forecast and how the results are used to derive a forecast for the 12-monthly peaks.

b) Please provide a schedule that sets out each model's predicted/forecast results for 2017-2022 and the resulting year over year growth rates. (Note: Predicted values would the model's prediction for those years where the actual results were known)

c) Please provide a schedule that sets out the growth rates applied to the base year values for purposes of deriving the forecast for each of the years after 2018 and compare these with the growth rates projected by each of models.

5.0-VECC-28

Reference: Exhibit E/T3/S1, pages 17-19

Preamble: Section 4.3 describes how the customer forecast is based on a customer survey and econometric analyses of individual customers.

a) Please describe more fully how Hydro One ensures that the forecasts developed for each of the individual customers sum to the total transmission forecast.

5.0-VECC-29

Reference: Exhibit E/T3/S1, page 10, pages 15-19 and pages 27-44

a) Please confirm that for all the models used to forecast transmission system load the impacts of CDM and embedded generation were added back to the historical data.

b) The monthly econometric model (page 27) does not appear to include any weather related variables. How was the effect of weather addressed in the model?

c) With respect to the impacts of CDM that were added back, were the actual impacts of demand response programs added back?

d) If the actual impacts of demand response programs were not explicitly added back, does this mean that the actual data used to develop the forecast models includes (i.e., has been reduced by) the impact of demand response programs?

5.0-VECC-30

Reference: Exhibit E/T3/S1, pages 31, 33, 35, 37 and 40
Exhibit E/T3/S1, Attachment 1 (Excel file)Energy Price Tab
Updated Ex/T3/S1, Attachment 1 (Excel file) Energy Price Tab
EB-2016-0160, Board Decision, page 68

Preamble: In its EB-2016-0160 Decision the Board stated: "The OEB notes Hydro One's agreement with the principle expressed by VECC that actual and forecast values derived on a consistent basis from the most up to date information available should be used for load forecasting purposes. The OEB urges Hydro One to continue to adhere to that principle and to examine whether alternative data sets available from other organizations such as the National Energy Board or from those responsible for preparing the next Long Term Energy Plan can be used in the preparation of future load forecasts".

a) With respect to the actual and forecast energy prices used in developing the load forecast (per E/3/1/1), please indicate which sources were used for which parts of the data set.

b) Please indicate what improvements Hydro One has made since EB-2016-0160 in the consistency of the energy priced data sources used for load forecasting purposes – per the Board's Decision.

c) Part of the June Update included revisions to the Energy Price Tab in Exhibit E/T3/S1, Attachment 1. It is noted that the titles now indicate the values are now expressed in "constant dollars" however only the values for 2004 and onwards were revised. Please explain precisely what changes were made in the update and whether any real changes (apart from changing the basis for the values) were made.

5.0-VECC-31

Reference: Exhibit E/T3/S1, pages 52-53

a) Please clarify which of the two forecasts is higher for the 18-month period starting January 1, 2019.

b) The Application states that "In contrast, Hydro One needs to take account of all possibilities, such as the extreme weather occurring during a weekend, when it comes to forecasting load for revenue purposes." Please reconcile this statement with the fact that the load forecast is weather normalized based on 31 years (per page 11).

d) The Application states that “Hydro One needs to forecast load net of demand response because load and, thereby, transmission revenue decreases due to demand response. Hydro One does so by implicit method where demand response is not added to the actual and forecast”. Please reconcile this approach with the OEB’s directive in its EB-2006-0501 Decision with Reasons, August 16, 2007 calling for the removal of the impact of DR programs from weather normal load forecasts because such programs are most effective in weather abnormal circumstances.

5.0-VECC-32

Reference: Exhibit E/T3/S1, Cover Letter
Updated Exhibit H/T1/S2, Attachment 11

Preamble: The Cover Letter states that “Hydro One’s 2018 audited financial statements for its transmission business will be finalized at the end of April 2019. At that time, Hydro One will update the Application to replace 2018 forecast numbers with actuals. These will be reflected in a Blue Page update that will be filed in mid-2019.” It appears that the Update (dated June 19, 2019) did not update any of the information in Exhibit E, Tab 3 regarding the load forecast.

a) With respect to the various Tables in Tab 3, Schedule 1, pages 1-26, were all of the 2018 values reported in the initial Application based on 2018 actual data? If yes, please explain how this is the case when the load forecast was prepared in December 2018. If not, please update those tables in Tab 3 that were based on forecast values for 2018.

b) Are more current economic forecasts (e.g. Appendix E) now available? If so, please provide an update to Appendix E.

5.0-VECC-33

Reference: Updated Exhibit H/T1/S2, Attachment 11
Updated Exhibit E/T3/S1, page 8 (Table 2)

Preamble: Attachment 11 states “Hydro One calculated the EE CDM impacts using updated annual peak savings by EE programs for 2006-2017 provided by the IESO.”

a) Please provide a schedule that sets out the updated annual peak savings by EE programs for 2006-2017 as provided by the IESO.

b) Please provide a schedule that compares these updated EE savings values for 2006-2017 with those used for purposes of developing the current forecast (i.e., the contribution of EE programs to the CDM values set out in Table 2 – Updated Exhibit E, Tab 3, Schedule 1).

c) If there is a difference, please explain why the load forecast was not updated to incorporate these revised values.

5.0-VECC-34

Reference: Updated Exhibit E/T3/S1, page 8 (Table 2)
Directive-CCF-Wind-down (http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework)
Directive-Interim-Framework (http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework)
Interim Framework CDM Plan – 20190524 (http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework)

a) Please confirm that the CDM forecast through to 2020 in Table 2 is based on the Conservation First Framework implemented by the previous provincial government.

b) In March 2019 the current Minister of Energy issued directives i) discontinuing the Conservation First Framework and the Industrial Accelerator Program and ii) establishing a new Interim Framework. On June 5, 2019 the IESO published the new framework setting out both those programs that would be continued and those that would be discontinued. The IESO also released new program budgets and targets for 2019 and 2020. What impact will the revised framework (which only continues some of the of original Conservation First Framework's programs) have on the forecast CDM savings for 2019-2022 as set out in Table 2?

6.0 EXHIBIT F – OPERATING COSTS

6.0-VECC-35

Reference: ExF/T1/S1/pg. 5

a) At the above reference Hydro One makes the following statement:

> Sustained funding at the 2019 bridge year level, or a reduction below the 2020 forecast amount, will pose unreasonable safety and reliability risks and will adversely affect Hydro One's ability to meet its customer needs and priorities.

Should Hydro One be required to make, for example, a 5% reduction to its proposed 2020 OM&A budget what specific program(s) would be eliminated which would cause an unreasonable safety or reliability risk.

b) Please explain how the following OM&A programs directly affect safety or reliability of service:

- Corporate Management

- Finance
- Human Resources
- Corporate affairs
- General Counsel and Secretariat
- Regulatory Affairs
- Research Development and Demonstration
- Transmission standards program

6.0-VECC-36

Reference: ExF/T1/S3/pg.10-

Hydro One notes that during the term of the proposed rate plan it must address remedial action for PCB contaminated equipment in order to comply with regulations requiring such containments be eliminated by December 31, 2025

a) Has Hydro One completed an inventory of all equipment which requires remedial action or replacement? If yes please provide a summary of that inventory.

b) Has Hydro One completed a business-project plan for the elimination of PCBs. If yes please provide that plan.

c) Do the costs shown in line 1 of Table 3 capture the entirety of the PCB elimination program for the years shown?

6.0-VECC-37

Reference ExF/T1/

a) Is the PSIT Support program an new initiative of Hydro One. If yes is the $15.8 an expected ongoing cost of running this program?

b) Did Hydro One complete a cost-benefit analysis of this program. If yes please provide that study.

6.0-VECC-38

Reference: ExF/T1/S7/pgs. 4-

a) Please provide more detail on the Productivity Placeholder initiative. Specifically please explain if this is a new initiative, how the program is expected to work, whether it represents a pilot initiative and if so, how it is to be assessed for future expansion to other parts of Hydro One's operations.

b) Are there any employee incentives associated with this initiative?

6.0-VECC-39

Reference: ExF/T2/S2/pg.2

a) Hydro One corporate management costs (Table 1)have increased significantly since its initial public offering ($16.4 million in 2015 and $26.9 million in 2019). Are these costs exclusively driven by higher compensation rates for senior managers? If not please show the amount driven by higher compensation costs (i.e. cost per FTE assigned to this function) and that due to other factors.

b) In the absence of legislated restrictions on compensation recovery would these costs be higher in 2020? If so by how much.

c) Table 2 – Allocated to Transmission- appears to show that although overall corporate management costs have risen well above inflation since 2015 those allocated to the transmission function have declined since 2015. Is this a correct interpretation of what Table 2 is showing? If so, does this result in the majority of the increase in this area been allocated to the distribution function? If that is correct please explain why.

6.0-VECC-40

Reference: ExF/T2/S2/pg.14/Table 8

a) Human resource functions have almost doubled from $6.8 million in 2015 to $12.2 in 2020. Please provide the increase in FTEs in that function since 2015 and the average and median 2015 annual salary and 2019 average and median salary for employees in the HR function.

6.0-VECC-41

Reference: ExF/T3/S1/pg.7

a) Hydro One has contracted for the service of Brookfield Johnson Controls Canada for service (BGIS Agreement). When did this agreement take effect?

a) Please list the services and the last actual year cost and last Board approved cost for those service.

b) Please provide the annual cost of this contract.

6.0-VECC-42

Reference: ExF/T4/S1/Table 2/pg.13

a) Please recast Table 2 to show the repatriation of the customer contact center from the other changes in FTE in the 2017 to 2022 period.

7.0 EXHIBIT G – COST OF CAPITAL AND CAPITAL STRUCTURE

7.0-VECC-43

Reference: ExG/T1/S1/pg.3-6

a) Has Hydro One carried out any analysis of the change in cost of long and medium term debt (new and old issue yields) pre and post its initial public offering? If so, please provide those studies.

b) Please update Table 4 to show the historical yields (on the same annual basis shown in the Table) for 2012 to 2020.

8.0 EXHIBIT H – DEFERRAL AND VARIANCE ACCOUNTS

8.0-VECC-44

Reference: Updated Exhibit H/T1/S1, page 4
Updated Exhibit H/T1/S5, Attachment 1

a) Please provide the forecast and actual export revenue values for 2016, 2017 and 2018 used to derive the annual Transactions Debit / (Credit) for each year set out in Attachment 1.

8.0-VECC-45

Reference: Updated Exhibit H/T1/S2, Attachment 11
EB-2016-0160, Exhibit E1/T3/S1, page 8 (Table 2)
EB-2016-0160, Exhibit I/Tab 12/VECC 28 f)

EB-2016-0160, Exhibit I/Tab 12/VECC 36

a) Please confirm that the CDM adjustments included in the load forecast for 2013 and 2014 used in EB-2012-0031 included the impact due to energy efficiency programs (EE), Code and standards (C&S) and DR programs per VECC 36 from EB-2016-0160

b) Please confirm that the CDM adjustments to the load forecast for 2017 and 2018 used in EB-2016-0160 only included the impacts includes EE programs & Codes and Standards - per VECC 28 from EB-2016-0160.

c) Please reconcile the response to part (b) with the statement in Attachment 11 that the the CDM peak savings assumptions in HONI's load forecast for 2017 per EB-2016-016 includes the impact due to energy efficiency programs (EE), Code and standards (C&S) and DR programs, which include the impact from the Industrial Conservation Initiative (ICI), Dispatched Load program, and DR auctions.

d) If the forecast CDM used EB-2016-0160 only included EE and C&S, why should the variance account determination also include ICI, Dispatched Load and DR?

8.0-VECC-46

Reference: EB-2016-0160, HON IRR VECC 27
Updated Exhibit H/T1/S2, Attachment 11

a) The Application states "Hydro One calculated the EE CDM impacts using updated annual peak savings by EE programs for 2006-2017 provided by the IESO. The monthly peak savings was derived using the monthly EE savings profile from the approved load forecast applied to the reported annual peak savings".

    i. Please provide the updated annual peak savings by EE programs for 2006-2017 provided by the IESO to Hydro One.

    ii. Please describe how Hydro One determined the monthly savings and the impact on the transmission billing determinants using this data. Please provide a schedule setting out the derivations.

    iii. Using the billing determinants from (ii) please show the calculation of the dollars associated with the EE variance as set out in Table 4 (Attachment 11)

b) Please confirm that (per VECC 27) the CDM values used in EB-2016-0160 to develop the load forecast for 2017 and 2018 were based on actuals for the years up to 2014 and on forecast values for the years thereafter.

c) If not confirmed please indicate for which years actual CDM results were used and reconcile with the response to VECC 27.

d) Please re-do the analysis in Table 2 (Attachment 11) using the incremental savings per IESO from the last year for which actual data was used in EB-2016-0160 up to 2017 for each category of CDM set out in Table 2.

9.0 EXHIBIT I1 – COST ALLOCATION TO UNIFORM TRANSMISSION RATE POOLS

9.0-VECC-47

Reference: Exhibit I1/T1/S2, page 8

a) What percentage of the Transformation Connection assets is accounted for by the Wholesale Revenue Metering assets for 2020?

b) How does the 2020 Wholesale Metering Service revenue compare (percentage-wise) with the 2020 costs allocated to the Transformation Connection rate pool?

9.0-VECC-48

Reference: Exhibit I1/T1/S2, page 2

Preamble: At lines 9-13 Hydro One Networks states that assets are functionalized based on the normal system operating condition of assets in-service as of the end of 2017.

a) Please explain how any additional transmission assets that are in-service for 2020 are functionalized.

9.0 -VECC-49

Reference: Exhibit I1/T2/S1

a) Please provide a schedule that lists the new Transmission Lines that were not included in EB-2016-0160. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Lines whose functional categorization has changed from that in EB-2016-0160 and provide an explanation as to the reason for the change.

9.0 - VECC-50

Reference: Exhibit I1/T2/S2

a) Please provide a schedule that lists the new Transmission Stations that were not included in EB-2016-0160. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Stations whose functional categorization has changed from that in EB-2016-0160 and provide an explanation as to the reason for the change.

9.0 - VECC-51
Reference: Exhibit I1/T3/S1

a) Please provide a schedule that lists the new Dual Function Lines that were not included in EB-2016-0160. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional categorization percentages it has been assigned and indicate why.

b) Please provide a schedule that lists those Dual Function Lines whose functional categorization percentages have changed from that in EB-2016-0160 and provide an explanation as to the reason for the change.

9.0 - VECC-52
Reference: Exhibit I1/T3/S2

a) Please provide a schedule that lists the new Generator Line Connections that were not included in EB-2016-0160. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional categorization percentages it has been assigned and indicate why.

b) Please provide a schedule that lists those Generator Line Connections whose functional categorization percentages have changed from that in EB-2016-0160 and provide an explanation as to the reason for the change.

9.0 - VECC-53
Reference: Exhibit I1/T3/S3

a) Please provide a schedule that lists the new Generator Station Connections that were not included in EB-2016-0160. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional categorization percentages it has been assigned and indicate why.

b) Please provide a schedule that lists those Generator Station Connections whose functional categorization percentages have changed from that in EB-2016-0160 and provide an explanation as to the reason for the change.

10.0 EXHIBIT I2 – RATE DESIGN FOR UNIFORM TRANSMISSION RATES

10.0-VECC-54

Reference: Exhibit I2/T2/S1, Attachment 1 (Table 1)

a) Please update Table 1 to include 2018.

b) With respect to Table 2, will dividing the number of customers who would be better off in each year by the number of occurrences (per Table 1) provide the average number of PST customers who had their peak outside of the peak period when the system also peaked outside the peak period?

c) With respect to page 10, were there any discussions with the IESO regarding the merits of altering the definition of the peak period so as to include hour 20?

10.0-VECC-55

Reference: Exhibit I2/T4/S1, pages 1-3
EB-2014-0140 Decision
EB-2014-0140, HONI's Tx 2015-2016 Transmission Revenue Requirement Application – Application, Settlement Agreement and Evidence

a) Please confirm that the parties to the EB-2014-0140 agreed on the ETS rate on the understanding that the methodologies, assumptions and scenarios used in the Elenchus Study do not have precedential value and may be challenged in subsequent proceedings.

b) Please confirm that the Board, in its EB-2014-0140 Decision, did not opine on the merits of or accept the methodologies, assumptions and scenarios used in the Elenchus Study.

10.0-VECC-56

Reference: Updated Exhibit I2/T4/S1, pages 3-4
Exhibit I2/T4/S1, pages 3-4

a) Please provide a schedule setting out the calculation of the export volumes for 2020, 2021 and 2022 as used in the initial Application.

b) Please provide a schedule setting out the calculation of the export volumes for 2020, 2021 and 2022 as used in the Updated Application.

End of document