VECC INTERROGATORY #1

Reference:
A-02-04p. 15

Interrogatory:

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)?

Response:

a) There are no costs in this proceeding related to Niagara Reinforcement project.

b) The completion of this project will not impact this current application including load forecast.
(Note – Hydro One is assuming that the word “competition” in the question above was intended to be “completion”).

VECC INTERROGATORY #2

Reference:
A-03-01-01

Interrogatory:

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.

Response:
No material changes were made between the December 14, 2018 2019-2024 Transmission Business Plan and the EB-2019-0082 Application request specifically for the capital renewal plan.

VECC INTERROGATORY #3

Reference:
A-03-01-01p. 19 -

Interrogatory:
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.

Response:
a) Please see Exhibit I, Tab 7, Schedule SEC-26 for a more detailed listing and description of initiatives. Please reference to the 'Category' column to reconcile to the productivity summary table provided in the Business Plan.

Witness: Joel Jodoin

VECC INTERROGATORY #4

Reference:
A-04-01p. 5
& EB-2018-0218 Hydro One Sault Ste. Marie LP, Decision with Reasons, pgs. 19-21.

Interrogatory:

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

Response:

a) Please see Exhibit I, Tab 01, Schedule OEB-5 part a) for a detailed discussion explaining how the proposed Productivity Factor (X) of 0% is meeting the filing requirements and is the appropriate Productivity Factor for Hydro One Transmission. Additionally, Exhibit I, Tab 01, Schedule OEB-6 explains the rationale as to why the decision in the HOSSM proceeding (EB-2018-0218) should not apply to the current application.

VECC INTERROGATORY #5

Reference:

Interrogatory:

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?

Response:

Please refer to Exhibit I, Tab 11, Schedule CCC-13. Additionally, Hydro One notes that page 14 of the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014, makes it clear that the use of an ACM was not appropriate for Hydro One, given its large, multi-year capital requirements.

VECC INTERROGATORY #6

Reference:
A-04-01p. 7
Capital Factor

Interrogatory:

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.

Response:

a) Line 13 of Table 2 identified as 'Less Capital Related Revenue Requirement in I-X' reflects the percentage of increase in Capital Related Revenue Requirement from the application of the Inflation and Productivity Factors (I-X) of the RCI formula. The calculation is based on a placeholder inflation rate for 2021 and 2022 of 1.4% and the proposed X factor of 0% as presented in Exhibit A, Tab 4, Schedule 1, Table 3.

b) As noted on page 9 of Exhibit A, Tab 4, Schedule 1, the proposed Productivity Factor and Capital Factors would remain unchanged in subsequent applications once approved by the OEB in this proceeding. The revenue requirement in subsequent years would be calculated using the proposed RCI updated only to reflect the OEB issued inflation factor for the proposed year.

c) Exhibit A, Tab 4, Schedule 1 Line 8 in Table 2 identified as 'Total Capital Related Revenue Requirement' is the calculation of the return on capital (Line 6 – Capital Related Revenue Requirement) less any productivity factor related to capital (Line 7 – Less Productivity Factor 0%). This is calculated based on the associated rate base for the given year. Namely, Depreciation Expense, Return on Equity, Return on Debt and Income Taxes. The capital expenditures which are further discussed in the TSP reflect the capital work that is requested in the application. Please refer to Exhibit C, Tab 1, Schedule 1 (Rate Base) and Exhibit C, Tab 2, Schedule 1 (In-Service Additions) for further details regarding the relationship between Capital Expenditures, In-Service Additions and Rate Base.

VECC INTERROGATORY #7

Reference:
A-04-01p. 7
Capital Factor

Interrogatory:

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.

Response:

a) The purpose and derivation of the capital factor is described in Exhibit A, Tab 4, Schedule 1. The statement in the question is incorrect. While the capital factor remains fixed throughout the term, the inflation factor will vary and therefore the revenue requirement impact will deviate from the projected increase in rate base over time thereby decoupling rates from costs.

b) Table 2 of Exhibit A, Tab 4, Schedule 1, 'Summary of Revenue Requirement Components' will be finalized at the Draft Rate Order (DRO) stage to reflect the OEB decision in the Application. The resulting capital factors for 2021 and 2022 will remain unchanged over the Custom IR term. During the annual updates for the 2021 and 2022 revenue requirement, Hydro One will calculate the revenue requirement using the proposed RCI updated to reflect the OEB issued inflation factor for the relevant year. This is consistent with the approach approved by the OEB in its decision on Hydro One Distribution's 2018-2022 Custom IR application (EB-2017-0049).

As Hydro One is proposing a Cumulative In-Service Variance Account (CISVA) any revenue requirement impact as a result of variances between actual in-service additions and OEB-approved in-service additions will be captured in the account. No amount would be recoverable from rate-payers due to this account being asymmetrical. As the threshold used is 98%, an entry would only be booked if in-service additions were 98% or less of the forecasted (OEB-approved) capital additions. If actual in-service additions are over 98% of forecasted (OEB-approved) capital additions, no entry would be booked. It should be noted that this account is calculated annually on a cumulative basis. Therefore in a scenario where an amount is booked to the account in Year 1, and in Year 2 the cumulative in-service additions are over 98% of the cumulative forecasted amount, no entry would be booked in Year 2, and the prior year's balance would remain.

c) Please refer to part b) above. Sample calculation of the account mechanics is provided in Exhibit H, Tab 1, Schedule 2 Attachment 5.

VECC INTERROGATORY #8

Reference:
A-04-01p. 10

Interrogatory:

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.

Response:

a) Please refer to Exhibit I, Tab 04, Schedule LPMA-3.

b) Please refer to Exhibit I, Tab 01, Schedule OEB-11.

c) Hydro One notes that as this account tracks variances on an annual basis and any underspending in earlier years will be captured in the account and refunded to customers. Please refer to Exhibit I, Tab 10, Schedule VECC-7 for detailed explanations of the mechanics.

VECC INTERROGATORY #9

Reference:

TSP-01-01p. 32

Interrogatory:

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?

Response:

a) The 2017 Transmission Customer Engagement Survey had supplemental questions for LDCs. These can be found in Exhibit B-1-1, Sec 1.3, Attachment 1, pages 54-56. Otherwise the survey was uniformly offered to all segments. Exhibit B-1-1, Sec 1.3, Attachment 1, page 21 breaks down the Power Quality responses by each segment, single vs. multi-circuit, and by region.

b) Hydro One maintains customer information in its Customer Relationship Management (CRM) database.

c) All transmission connected customers and LDCs have access to their own Account Executive. Hydro One Account Executives make best efforts to meet with their customers each year, or as necessary depending on the level of activity between the customer and Hydro One.

d) Hydro One conducts several meetings with LDCs each year, some of which are group settings. These meetings present an opportunity to discuss specific issues, and general LDC related issues.

VECC INTERROGATORY #10

Reference:
TSP-03-03p. 8

Interrogatory:

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.

Response:

a)

Application	$, millions	Application Reference
EB-2013-0416	18.6	Exhibit D2-2-3, Reference O-04 – New Facility Development
EB-2014-0140	21.4	Exhibit D2-2-3, Reference O-02 – Backup Control Centre – New Facility Development

b) The initial planner's estimate was exclusively for a Backup Control Centre, based upon two key assumptions: i) it was to be built on a Hydro One transmission station, and ii) telecommunication infrastructure would be available. Coming out of the planning needs assessment, it was learned that multiple lines of business required the same critical support infrastructure. As a result, a scope was created for an Integrated System Operations Centre ("ISOC"), which added the following functionalities:

- An Integrated Telecommunication Management Centre,
- A Security Operations Centre,
- Office space for Operating support staff, and
- Incremental data centre space to relieve constraints at the existing data centre and accommodate the additional lines of business at the ISOC.

Furthermore, the ISOC necessitated new land acquisition and telecommunication infrastructure.

c) The OEB approves funding at a macro level not at the project level and when the approval is less than what Hydro One requests, Hydro One reviews and optimizes the funding across the projects based on risk mitigation, customer commitments and other considerations. Funds are reallocated and reinvested; there are no reductions to the rate base. Details of the investment planning and redirection processes are included in Exhibit B, Tab 1, Schedule 1, Section 2.1.

VECC INTERROGATORY #11

Reference:
B-01-03

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

Response:
Please refer to Exhibit B, Tab 1, Schedule 1, Section 2.1 “System Access”

VECC INTERROGATORY #12

Reference:

C-02-01

Interrogatory:

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)

Response:

a) Please note that capital contributions from other market participants are excluded from Hydro One's net capital expenditure and in-service additions, and Hydro One does not seek recovery of these costs in either historic or test years. This information is not relevant to Hydro One's historic performance nor the proposed revenue requirement for the test years.

The capital contributions attributable to the different capital categories for each of the test years are included in Exhibit B, Tab 1, Schedule 1, Section 3.3, Tables 5-8. These are summarized and also expressed as percentages below.

Table 1 - 2020-2022 Test Year Capital contributions (in $ millions)

	2020		2021		2022	
	$	**%**	**$**	**%**	**$**	**%**
System Access	130.9	78	46.7	57	51.3	75
System Renewal	3.8	2	6.1	7	8.3	12
System Service	34.2	20	29.7	36	8.5	13
General Plant	0	0	0		0	0
Total	**168.9**		**82.5**		**68.1**	

Witness: Andrew Spencer

VECC INTERROGATORY #13

Reference:

C-02-01-01p. 24 & 42
(EB-2014-0160 Exhibit B1, Tab 3, Schedule 2-)

Interrogatory:

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).

Response:

a) Please see tables below for requested actuals from 2014-2018 (and proposed and DRO adjusted amount for 2017 and 2018)

	CAPEX									ISA								
	2014	2015	2016	2017	2017	2017	2018	2018	2018	2014	2015	2016	2017	2017	2017	2018	2018	2018
	Actuals	Actuals	Actuals	Proposed	DRO Forecast	Actuals	Proposed	DRO Forecast	Actual	Actuals	Actuals	Actuals	Proposed	DRO Forecast	Actuals	Proposed	DRO Forecast	Actual
Sustaining Capital																		
Transmission Stations																		
Circuit Breakers	25.0	7.1	4.1	1.1	0.4	0.4	0.0	3.0	0.1	30.0	7.7	8.7	1.2	0.7	0.8	0.4	7.1	0.0
Power Transformers	111.1	43.5	13.0	0.0	1.1	0.0	0.0	0.5	-0.7	97.2	60.8	39.1	15.0	22.6	20.8	2.6	4.5	1.7
Other Power Equipment	27.5	12.5	5.3	0.0	0.1	0.0	0.0	0.2	0.3	36.3	14.2	9.3	2.2	1.0	2.3	1.1	3.3	0.2
Ancillary Systems	22.0	17.1	7.6	1.3	1.2	1.1	0.0	0.5	0.7	29.3	22.3	17.0	3.5	2.6	0.5	1.9	3.7	5.3
Station Environment	10.5	3.8	1.9	0.0	0.2	0.4	0.0	0.0	0.0	20.5	3.9	2.8	0.2	1.4	1.5	0.1	0.0	0.0
Integrated Station Investments	157.3	374.2	469.1	457.8	469.0	481.0	404.7	397.4	410.7	113.7	206.9	330.6	407.1	439.6	389.2	364.5	387.3	519.3
TX Transformers Demand and Spares	0.0	27.2	24.6	25.3	28.2	26.8	25.8	67.2	82.6	0.0	27.3	18.1	17.3	25.7	23.2	22.5	70.4	79.7
Protection and Automation	97.9	60.2	40.5	45.2	27.0	20.9	59.1	58.1	44.4	125.9	80.0	44.8	46.7	20.6	16.7	54.1	73.6	51.4
Site Facilities and Infrastructure	30.0	20.3	10.3	6.7	13.8	13.0	6.7	10.6	16.7	34.3	30.3	14.0	12.0	13.2	11.9	8.7	9.8	17.5
Total Transmission Stations Capital	481.3	565.8	576.3	537.5	541.0	543.6	496.2	537.5	554.9	487.3	453.5	484.4	505.2	527.4	466.9	456.0	559.7	675.0
Transmission Lines																		
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	119.4	125.0	165.8	237.0	196.5	196.3	323.4	227.8	225.6	111.4	112.8	163.0	265.4	200.5	199.9	267.9	177.3	195.8
Underground Cables Refurbishment and Replacement	20.6	3.5	1.7	2.3	7.2	10.7	22.5	30.1	16.5	57.2	3.4	0.3	0.5	0.4	0.3	23.8	36.5	2.4
Total Transmission Lines Capital	140.0	128.4	167.5	239.3	203.7	207.1	345.9	257.9	242.1	168.5	116.2	163.4	265.9	200.9	200.2	291.7	213.8	198.2
Total Sustaining Capital	**621.3**	**694.3**	**743.8**	**776.8**	**744.7**	**750.6**	**842.1**	**795.4**	**796.9**	**655.8**	**569.7**	**647.8**	**771.1**	**728.3**	**667.1**	**747.7**	**773.5**	**873.2**
Development Capital																		
Inter Area Network Transfer Capability	45.9	86.3	80.8	79.8	36.0	36.0	59.8	39.0	48.9	50.7	2.1	13.7	5.5	1.3	16.7	264.6	228.0	205.3
Local Area Supply Adequacy	49.1	64.9	54.3	43.8	46.9	45.1	45.7	28.0	20.7	33.6	8.9	137.4	37.6	55.7	57.9	28.7	10.3	10.1
Load Customer Connection	14.6	7.7	13.6	58.1	33.8	42.3	57.4	18.1	28.5	29.3	9.4	6.6	5.9	0.2	49.1	71.8	62.8	8.6
Generator Customer Connection	1.7	-1.7	0.2	0.0	0.0	0.4	0.0	1.2	0.3	2.1	-2.0	0.9	1.4	0.2	1.7	0.3	0.6	-0.8
P&C Enablement for Distributed Generation	1.2	2.1	1.3	0.0	0.6	0.8	0.0	0.0	0.5	1.7	1.8	1.9	0.2	1.3	0.4	0.2	0.5	0.5
Risk Mitigation	17.0	3.1	1.8	12.6	10.9	9.5	5.2	4.3	2.6	46.6	8.3	1.1	11.4	10.3	9.1	7.0	3.7	0.7
Power Quality	0.0	0.0	0.2	2.1	2.3	2.3	2.1	4.1	1.4	0.0	0.0	0.1	2.5	2.3	1.0	2.3	2.6	1.8
TS Upgrades to Facilities Distribution Generation	-1.0	-1.2	0.0	0.0	0.0	0.0	0.0	0.0		-0.4	-1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Performance Enhancement	0.5	1.3	0.4	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.6	1.5	0.1	0.0	0.2	0.0	0.2	0.0
Smart Grid	2.5	3.5	3.3	0.0	0.9	0.7	0.0	0.0	0.2	14.2	0.0	20.5	0.0	0.9	0.7	0.0	0.0	0.2
Total Development Capital	**131.6**	**166.0**	**156.1**	**196.4**	**131.4**	**137.1**	**170.2**	**94.9**	**103.1**	**177.9**	**27.9**	**183.5**	**64.6**	**72.2**	**137.0**	**374.9**	**308.7**	**226.4**

	CAPEX									ISA								
	2014	**2015**	**2016**	**2017**	**2017**	**2017**	**2018**	**2018**	**2018**	**2014**	**2015**	**2016**	**2017**	**2017**	**2017**	**2018**	**2018**	**2018**
	Actuals	**Actuals**	**Actuals**	**Proposed**	**DRO Forecast**	**Actuals**	**Proposed**	**DRO Forecast**	**Actual**	**Actuals**	**Actuals**	**Actuals**	**Proposed**	**DRO Forecast**	**Actuals**	**Proposed**	**DRO Forecast**	**Actual**
Operations Capital																		
Grid Operating and Control Facilities	23.3	14.2	7.6	11.4	7.7	6.0	19.3	29.1	3.8	8.2	34.0	9.6	1.9	0.2	0.2	4.4	5.3	7.0
Operating Infrastructure	5.1	1.4	4.6	14.0	5.4	4.8	11.5	13.8	5.8	9.1	3.6	3.6	6.6	4.4	3.3	8.0	9.1	3.9
Total Operations Capital	**28.4**	**15.6**	**12.2**	**25.4**	**13.0**	**10.8**	**30.8**	**42.9**	**9.6**	**17.3**	**37.5**	**13.2**	**8.5**	**4.5**	**3.4**	**12.4**	**14.5**	**10.9**
Capital Common Corporate Costs and Other Costs																		
Transport and Work, and Service Equipment	22.0	22.1	24.6	24.1	17.5	16.9	25.0	16.6	9.3	22.0	22.1	24.6	23.0	17.6	16.9	24.9	16.5	9.3
Information Technology (including Cornerstone)	26.8	21.6	35.9	31.4	34.4	32.8	28.1	28.9	42.0	28.6	15.1	22.0	41.9	39.5	40.6	24.1	40.5	35.1
Facilities & Real Estate	13.7	22.7	13.9	18.4	9.1	6.7	20.9	21.3	7.0	12.8	26.5	19.1	18.7	5.7	7.3	20.7	24.8	5.4
Other (including CDM)	0.9	0.7	0.3	3.7	0.0	-1.1	5.1	0.0	-0.7	0.0	0.3	0.0	3.7	0.0	0.0	5.1	0.0	0.0
Total Capital Common Corporate Costs and Other Cos	**63.4**	**67.1**	**74.6**	**77.6**	**60.9**	**55.3**	**79.1**	**66.8**	**57.6**	**63.4**	**64.0**	**65.7**	**87.2**	**62.7**	**64.7**	**74.7**	**81.7**	**49.8**
Total Transmission Capital	**844.6**	**943.0**	**986.7**	**1076.1**	**950.0**	**953.9**	**1122.2**	**1000.0**	**967.3**	**914.5**	**699.1**	**910.2**	**931.4**	**867.7**	**872.3**	**1209.7**	**1178.4**	**1160.4**

Witness: Andrew Spencer

VECC INTERROGATORY #14

Reference:
D-02-01-01p. 3

Interrogatory:

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.

Response:

a) When the standards were developed, the rational for different customer delivery point performance standards based on load size was provided in the following Board document: RP-1999-0057, EB-2002-0424. Following is a copy of the related materials from the document.

2.3.1 Load Grouping for Group (Outlier) CDPP Standards – General

Hydro One has proposed to apply different performance standards depending on the size of total average station load being served. For this purpose, load would be classified in one of four load bands (0-15 MW, 15-40 MW, 40-80 MW and >80 MW).

Hydro One took the position that the use of load bands accommodates normal year-to-year delivery point performance variations, limits the number of delivery points that are to be considered "performance outliers" to a manageable level, is commensurate with customer value ("the bigger the load the greater the level of reliability"), and will allow, or direct, focus on reliability improvements at the "worst" performing delivery points.

As evidence of the reasonableness of the methodology of basing performance standard on load size, Hydro One pointed to the Independent Electricity System Operator's ("IESO") Supply Deliverability Guidelines. Those Guidelines, which apply to preconnection studies for transmission customer connections, contain as a basic premise that the level of reliability of supply should be related to the size of the load being served, i.e., the larger the load, the greater the level of reliability. Similarly, in general the greater the load affected, the shorter the duration of the interruption is desired. The Guidelines also refer to the former Ontario Hydro's Guide to Planning Regional Supply System Deliverability (also known as the "E2" Guide). That Guide reflects a similar approach by using groupings according to load size for purposes of establishing the maximum acceptable severity of interruption.

Hydro One also submitted a survey of customer interruption costs ("CIC"), which represent the economic value to customers of unsupplied MWh of energy. The survey indicated that, for a given duration of interruption, the CICs increase as the size of the load increases. Hydro One then calculated a "Customer Value of Reliability" based on the number of interruptions that would result in different levels of CICs being achieved, up to a "CIC Ceiling" equal to Hydro One's annual transformation and line connection costs for a 15 MW load.

The Board considers that the use of a grouping methodology for performance standard purposes strikes the right balance with respect to practical application and accuracy. The Board finds that Hydro One's approach, based on a measure of the customer's value of reliability which varies with the size of the load served, is reasonable. Although Hydro One is not able to estimate the value that one megawatt represents to each customer in terms of some common quality, such as profit or productivity, the Board finds that the CIC concept is not unreasonable as a proxy.

b) Ontario transmission system was well developed in 70s and 80s. The system had relatively good reliability performance in 90 due to stable equipment performance. The overall system T-SAIDI performance in this period is better than that from 2000s or 2010s, where aging equipment failure is a main contributor to the later.

c) It is possible to update the standards based on 2000-2018 data, however, there will be no impact to customers as a result of doing so.

d) Over the last five years Customer Delivery Points below the minimum CDPP triggered have been between 84 - 105. Hydro One has completed assessments of all of these 84 DPs for 2017 which are determined based on the three year performance history. 2018 analysis is expected to be completed by Q1 2020. Hydro One consults with its customer on a regular basis, such as planning and operating meeting or different stages of ongoing sustainment programs and projects. In most cases, mitigation measures are part of Hydro One sustainment planning and assessments for safe, secure and reliable operation. Hydro One undertakes customer specific consultation for performance failing below the minimum CDPP if and when a) mitigation results in any changes to system configuration affecting customer(s) and b) a customer contribution is required to implement mitigation.

VECC INTERROGATORY #15

Reference:
D-02-01-01

Interrogatory:

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.

Response:

a) Correct. Where the three-year rolling average of the delivery point performance falls below the minimum Group CDPP Standard, Hydro One's level of incremental investment to improve the group outlier's reliability performance will be limited to the present value of three years' worth of transformation and/or transmission line connection revenue associated with the delivery point. Any funding shortfalls for improving delivery point reliability performance will be made up by the affected delivery point customers. Hydro One is of the view that this sharing of costs between the affected customers and ratepayers is necessary to strike a balance that encourages proceeding with only those reliability performance improvements that are technically and economically practical and to limit the subsidization of reliability improvement costs by other pool customers.

VECC INTERROGATORY #16

Reference:

E-01-01p. 1

Interrogatory:

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.

Response:

a) Please see Exhibit I, Tab 01, Schedule OEB-149 for the details requested for 2018-2020.

The OEB approved amounts for 2015-2017 are outlined in the below table:

OEB Approved Figures ($M)	2015	2016	2017
External Revenues	(31.8)	(32.2)	(28.2)
Export Tx Service Revenue	(30.9)	(31.7)	(39.2)
MSP Revenue	(0.3)	(0.2)	(0.3)
Low Voltage Switch Gear Credit	12.8	13.0	13.4

VECC INTERROGATORY #17

Reference:
E-02-01p. 2

Interrogatory:
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.

Response:
a) Table 1 below sets out the Proposed, Approved, and Actual (2015-2018) amounts.

Table 1 – Summary of External Revenues

($ millions)	EB-2014-0140						EB-2016-0160						EB-2018-0130	
	2015			2016			2017			2018			2019	
	Proposed	Approved[1]	Actual	Proposed	Approved[1]	Actual	Proposed	Approved	Actual	Proposed	Approved	Actual	Proposed	Approved
Secondary Land Use	14.3	17.7	34.3	14.5	17.9	24.9	15.4	15.4	20.1	15.6	15.6	25.6	17.6	15.6
Station Maintenance	7.2	7.2	9.5	7.3	7.3	6.2	5.3	5.3	3.9	5.3	5.3	4.6	4	5.3
Engineering & Construction	-	-	0.4	-	-	0.2	-	-	0.3	-	-	0.1	0.3	-
Other External Revenues	6.9	6.9	10.1	7.0	7.0	11.0	7.5	7.5	11.2	7.6	7.6	9.1	9.4	7.6
Totals	**28.4**	**31.8**	**54.3**	**28.8**	**32.2**	**42.3**	**28.2**	**28.2**	**35.5**	**28.5**	**28.5**	**39.4**	**31.3**	**28.5**

1 - Settlement, Issue 4. Are Other Revenue (excluding export revenue) forecasts appropriate?

VECC INTERROGATORY #18

Reference:
E-02-01p. 1-2

Interrogatory:
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.

Response:
a)

Table 1 – External Revenue Margins (in $ millions)

	Actual		Bridge	Test Year		
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Secondary Land Use	20.1	25.6	17.6	17.9	18.2	18.5
Station Maintenance	1.0	1.7	0.5	0.5	0.5	0.5
Engineering & Construction	-	-	0.0	0.0	0.0	0.0
Other External Revenues	10.8	7.3	9.3	9.1	10.1	9.3
Total	**31.9**	**34.6**	**27.3**	**27.5**	**28.8**	**28.3**

VECC INTERROGATORY #19

Reference:

E-02-01p. 3-4

Interrogatory:

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?

Response:

a)

Provincial Secondary Land Use Program Revenue				
$ (in millions)	2015	2016	2017	2018
Easements	$ 12.5	$ 4.3	$ 1.8	$ 2.5
Operational Land Sales	$ 1.7	$ 2.7	$ 0.3	$ 0.9
Total	$ 14.2	$ 7.0	$ 2.1	$ 3.4

b) The fluctuations in revenue levels associated with Provincial Secondary Land Use Program that is run in conjunction with Province (Infrastructure Ontario) are mainly due to isolated one-time events such as granting real estate easements rights in a given year. The easements rights granted to various third parties and respective revenue funds obtained as result of that can vary each year depending on business opportunities in terms of secondary utilizations of corridor lands. It is important to note that HONI does not control the outcomes, nor the time table when such transactions will occur, which involve third party negotiations and specific business circumstances in which proponents will require or express interest to obtain real estate rights from the Province (Infrastructure Ontario), therefore it is difficult to forecast beyond one year time frame. As result of this situation regulatory variance account has been established to account for these variances given planning challenges.

Witness: Andrew Spencer

VECC INTERROGATORY #20

Reference:
E-02-01p. 2 & 6

Interrogatory:

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.

Response:

a) See table below.

		Actual	Actual	Actual	Actual	Bridge
		2015	2016	2017	2018	2019
Tx Idle Lines		$ 4.0	$ 4.0	$ 3.9	$ 4.0	$ 3.1

b)
   i. The primary contributor to the decrease of $2.1M between the 2 years is due to cessation of temporary bypass charges to Toronto Hydro in 2018, which resulted in approximately $2M in lost revenue when comparing the two years. Note that the temporary bypass charge in 2017 was double the usual annual charge of as it represented two years of temporary bypass charge for Toronto Hydro (timing of billing).

   ii. The forecast from 2020 to 2021 increases as a result of the vegetation management cycle planned to be completed for Bruce to Milton Limited Partnership in 2021. This cycle occurs every 6 years.

iii. The forecast in 2022 decreases relative to 2021 as the vegetation management cycle for Bruce to Milton Limited Partnership is planned to be completed in 2021 and will not occur again until 2027.

VECC INTERROGATORY #21

Reference:
E-02-01

Interrogatory:

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.

Response:

a) Although it is not noted in this evidence, late payment interest charges on overdue non-energy accounts related to Transmission are accumulated. The total annual interest revenue for 2017 was $42k and 2018 was $38k. These dollars are not included in other Revenue per the evidence, but rather are factored into Transmission Revenues at a high level.

b) There is essentially no other interest income associated with Hydro One Networks Transmission business as cash balances are kept at minimal levels.

c) Late payment interest charges on over-due Non-Energy Accounts is not included in the determination of Revenue requirement (immaterial).

VECC INTERROGATORY #22

Reference:
E-03-01p. 1 & 4

Interrogatory:
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?

Response:
a) At the time the forecast was prepared, actual 2018 load was not available; but when this Application was prepared in early 2019, the 2018 load figures were available and provided in the initial Application. Since the 2018 actual load figures were only marginally different from the forecast (i.e. within 11 MW as shown in the response to Exhibit I, Tab 10, Schedule VECC-26, part b, subpart iii), the forecast values for the years 2019 to 2022 were left unchanged. Moreover, if the forecast growth rates were applied to the new 2018 base, the forecast Hydro One is requesting for approval would have been marginally lower, leading to higher rates.
   i. Ontario electricity demand was available and used up to October 2018.

   ii. The 2006 to 2015 values for CDM savings are actual values based on the 2016 OPO. The 2016 to 2017 savings were treated as the "Estimated" Actual based on the information available at the time of the preparation of the load forecast. As mentioned in the response to Exhibit I, Tab 10, Schedule VECC-33 part c, the historical peak savings are not used for the load forecast. The load forecast growth rates are derived based on the energy model.

iii. Annual explanatory variables and Ontario total energy figures were available and used up to and including 2017. Annual sectorial figures were available and used up to and including 2016. Monthly figures for residential building permits were available and used up to and including September 2018. Quarterly figures for Ontario GDP were available and used up to and including the second quarter of 2018.

VECC INTERROGATORY #23

Reference:

E-03-01p. 5-6

Interrogatory:

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

Response:

a) The sources for Population data is referenced in Exhibit E, Tab 3, Schedule 1, page 39, lines 7-9. The data on actual Commercial floor space is from Construction Market Data Group Inc. ("CMD"). The forecast was prepared by Hydro One in December 2018.

Witness: Bijan Alagheband

VECC INTERROGATORY #24

Reference:
E-03-01p. 1 & 7-8

Interrogatory:
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.

<u>Response:</u>

a) The requested information is provide in the Tables 1 and 2 below:

Table 1: CDM peak savings (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EE and C&S	289	778	893	997	1167	1318	1470	1621	1820	1942	2167	2099	2391	2799	3197	3341	3509
Data Source	OPA 2011 IPSP (Integrated Power System Plan)							OPA 2013 LTEP (Long Term Energy Plan)									
Actual/ Forecast	Estimated Actual' since there is no verfied results available for all programs												Forecast				

Table 2: CDM energy savings (TWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EE and C&S	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0
Data Source	2013 LTEP (Long term energy plan)																
Actual/ Forecast	Actual (2006-2012)							Forecast (2013-2022)									

b) i. Yes, the 2016 OPO introduced new CDM figures for energy for 2011 to 2022 as compared to the 2013 LTEP. The comparison of the LTEP and OPO's 2006 to 2022 energy savings is provided in Table 3 below:

Table 3: Comparison of the LTEP and OPO Energy Savings

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
LTEP 2013 total energy savings (2006-2012 actual)	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0
OPO 2016 Total energy savings TWh (2006-2015 actual)	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	12.8	14.3	15.9	17.8	19.5	20.7	20.9	21.1

ii. In the 2016 OPO, the IESO did not address/update its expectations regarding future CDM peak savings due to energy efficiency ("EE") and code & standards ("C&S").

c) i. No, the 2017 LTEP did not provide any update on the energy CDM savings from EE and C&S programs.

ii. Not applicable based on response to part (c), subpart (i) above.

d) Hydro One has taken into account all the available CDM forecasts to be assured that the assumptions used for the load forecast are reasonable. The information includes:

1	OPA's 2011 IPSP	https://cms.powerauthority.on.ca/integrated-power-system-plan
2	OPA's 2013 LTEP	http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/Long-Term-Energy-Plan/LTEP_2013_English_WEB.pdf?la=en
3	IESO's 2016 OPO	http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook
4	2017 LTEP	https://files.ontario.ca/books/ltep2017_0.pdf
5	IESO's provincial wide verified CDM result	http://www.ieso.ca/en/Sector-Participants/Conservation-Delivery-and-Tools/Conservation-Targets-and-Results
6	IESO's Technical Planning Conference in September 2018	http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Technical-Planning-Conference
7	IESO 2006-2017 saving & persistence table	This information has been provided in excel format, please refer to Attachment 1 of this response.

e) Hydro One's methodology is similar to the IESO's. Both HONI and the IESO have the same sub-categories for the EE and C&S components. The treatment of the EE and C&S impact in the load forecast is the same between HONI and the IESO. The only difference is that the IESO treats the demand response ("DR") as a resource and Hydro One treats the DR as a load curtailment.

f) For clarification, the information provided by IESO in March 2018 load forecast meeting was not related to CDM used in developing the load forecast. In that meeting, the IESO verbally confirmed that the CDM impact on peak, as used in this Application for developing the load forecast and presented in Table 2 of Exhibit E, Tab 3, Schedule 1 on page 8, is unchanged and appropriate.

i/ii/iii. Please see response to part (f).

g) i. No.

ii. The reference is to all the information available at the time of preparation of the load forecast and variance account calculations as described in the response to part (d) above.

h) i. This information has been provided in Table 1 above. The LTEP 2013 represents the latest IESO figures, please see response to part (f), where the IESO in March 2018 confirmed that this CDM peak impact data was unchanged and appropriate.

ii. Not applicable, please see response to part (h) subpart (i) above.

iii. The IESO's latest figures have assumed that actual results to-date are equal to those set out in the 2013 LTEP.

iv. The IESO has not updated its CDM peak forecast since the 2013 LTEP.

v. The data has not been updated to reflect the "verified results for 2013 and 2014" because the amounts used for the purposes of the CDM variance account are only related to the OPA-funded, LDC-delivered, 2011-2014 target programs as per the Settlement Agreement in EB-2012-0031. This is different from the historical total peak savings in the 2013 LTEP which include savings from **<u>all</u>** programs in 2006-2014.

VECC INTERROGATORY #25

Reference:
E-03-01p. 7 & 8

Interrogatory:

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.

Response:

a) The peak savings for 2006-2017 are ‘estimated” actual and peak savings for 2018-2022 are forecasted value.

b) Yes.

c) Not applicable, please see response to part (b) above.

d) Please see the response to Exhibit 1, Tab 10, Schedule VECC-24 part (d), the IESO 2006-2017 Savings & Persistence Table.

e) Hydro One derived monthly CDM savings using IESO’s (formerly the OPA’s) hourly load shape. The annual peak savings (July) is applied to the monthly saving profile to derive the monthly peak savings, and 12-month average peak savings, for the actual and forecast periods.

f) The requested information is provided in the table below.

Year	Energy Efficiency (EE)	Code and Standards (C&S)	Total Cumulative CDM Impact on Peak Demand*
2006	289	0	289
2007	760	18	778
2008	853	40	893
2009	930	67	997
2010	1,060	107	1,167
2011	1,034	284	1,318
2012	1,141	329	1,470
2013	1,248	373	1,621
2014	1,435	386	1,820
2015	1,528	413	1,942
2016	1,662	505	2,167
2017	1,575	525	2,099
2018	1,752	639	2,391
2019	2,022	777	2,799
2020	2,321	876	3,197
2021	2,357	984	3,341
2022	2,470	1,039	3,509

* The figures represent the load impact of CDM on summer peaks

g) Confirmed.

h) Confirmed.

Witness: Bijan Alagheband

VECC INTERROGATORY #26

Reference:
E-03-01p. 1, 9 & 19-21

Interrogatory:
Premable:
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.

Response:
a) Please see response to Exhibit I, Tab 10, Schedule VECC-22 part (a). The actual 2018 load was not available at the time the forecast was prepared; but when this Application was prepared in early 2019, the load figures were available and provided. Thus, initially, the forecast base year was 2017.

b) The growth rates were applied to the forecast values of the 2018 charge determinants.

   i. Please see response to part (b) above.

   ii. When the 2018 actual became available, the 2018 figures in Exhibit E, Tab 3, Schedule 1 were updated to reflect 2018 actual. However, the text on page 21 was overlooked and should have been changed to:

   "*Hydro One Transmission delivered an average of 22,159...*".

   iii. Please see the following table for the comparison of 2018 actual and forecast.

Comparison of 2018 Actual and Forecast
(12-Month Average Peak)

Peak	Forecast	Actual	Acual Less Forecast
Ontario Demand	19,667.8	19,657.3	-10.5
Network	19,686.0	19,678.3	-7.6
Line Connection	19,148.1	19,137.4	-10.6
Transformation Connection	16,317.9	16,329.1	11.2

VECC INTERROGATORY #27

Reference:
E-03-01p. 15-19

Interrogatory:
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.

Response:
a) No, none of the models used provides a forecast of each of the 12 monthly peaks. As noted on page 19 of Exhibit E, Tab 3, Schedule 1, the forecast for the 12-month average peak value was derived by applying the forecast growth rate to its base year value. A forecast of the individual 12 monthly peaks is not derived by Hydro One for load forecasting purposes.

b) The requested information is provided in Table 1 below. The figures for annual econometric and end-use models are for Ontario electricity usage and do not include transmission losses. Figures for the monthly model are at generation level and, as such, include transmission losses.

Table 1
Forecast for Econometric and End-Use Models
(GWh)

	Econometric Models		
Year	Monthly	Annual	End-Use Model
2017	152,684	149,880	150,326
2018	157,727	149,566	151,180
2019	160,019	148,180	152,587
2020	158,969	146,672	152,735
2021		145,820	151,879
2022		145,242	150,966

c) The requested information is provided in the following Table 2. The final growth rates include the load impact of developments in the Leamington and surrounding areas.

Table 2
Forecast Growth Rates
(%)

	Econometric Models				
Year	Monthly	Annual	End-Use Model	Average	Final
2019	1.5	-0.9	0.9	0.5	1.3
2020	-0.7	-1.0	0.1	-0.5	1.7
2021		-0.6	-0.6	-0.6	-0.1
2022		-0.4	-0.6	-0.5	-0.1

VECC INTERROGATORY #28

Reference:

E-03-01p. 17-19

Interrogatory:

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

Response:

a) As noted in Exhibit E, Tab 3, Schedule 1, pages 17-19, the forecast for large utility customers and industrial customers are used to drive the customer delivery point forecast, which are then scaled to the total transmission forecast.

Witness: Bijan Alagheband

VECC INTERROGATORY #29

Reference:
E-03-01p. 10, 15-19 & 27-44

Interrogatory:

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?

Response:

a) For the Monthly econometric model, both CDM and embedded generation were added back to the actual. The sectorial models are at end-use level so that they already reflect all sources of generation. Consequently, only CDM was added back to the actual.

b) This is because the dependent variable in the monthly econometric model is weather-corrected load so that it does not depend on weather conditions.

c) No.

d) Demand response programs are of a peak-shifting nature so they do not have an impact on monthly and annual energy usage. Consequently, the energy consumption was not reduced by such programs.

Witness: Bijan Alagheband

VECC INTERROGATORY #30

<u>Reference:</u>
E-03-01 p. 31, 33, 35, 37 and 40 E-03-01-01p. 68

<u>Interrogatory:</u>
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.

<u>Response:</u>
a) All energy prices up to 1998 are from Ontario Hydro. From 1999 to 2001 all energy prices are from Global Insight. From 2002 to 2012 all energy prices are from National Energy Board ("NEB"). For 2013 all energy prices are from the 2013 LTEP except for price of coal in industrial sector, which is from Global Insight. Since 2014 all energy prices are from NEB except for price of coal in industrial sector, which is from Global Insight, because the latest NEB energy price forecast did not include

price of coal. Energy prices after 2013 were forecast values and therefore were updated by NEB 2018 actuals.

b) Hydro One has always used the most up-to-date information for energy prices. For this Application, the most up-to-date information was available from the NEB and, therefore, NEB prices were used. In EB-2016-0160, a uniform set of up-to-date information was not available and, consequently, Hydro One used different sources.

c) The June Update to the Energy Price Tab in Exhibit E, Tab 3, Schedule 1, Attachment 1 was intended only to clarify that all energy prices presented in that worksheet are in constant dollar. The other changes to that worksheet were not related to the clarification about constant dollars, but rather, were corrections to align the energy prices shown in that worksheet with the energy prices actually used in this Application.

VECC INTERROGATORY #31

Reference:
E-03-01p. 52-53

Interrogatory:

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).

c) 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.

Response:

a) Hydro One's forecast is higher than IESO forecast after correcting for definitional differences as detailed in Exhibit E, Tab 3, Schedule 1, pages 52 to 53.

b) This statement reflects the contrast between the IESO and Hydro One methods regarding the treatment of extreme weather in relation to calculating monthly (rather than daily) peak. Monthly peak normally occurs during extreme weather in each month. Hydro One needs to calculate monthly peak which drives the collection of transmission revenue, while the IESO needs to calculate monthly peak for reliability purposes. As noted in Exhibit E, Tab 3, Schedule 1, pages 52 to 53, the IESO method assumes extreme weather occurs on the busiest day of the week (Wednesday). The way IESO does this is to calculate the load impact of average extreme weather, based on 31 years of weather data, for each month and then add it to non-weather related load on a Wednesday in that month for reliability purposes. Clearly, if such extreme weather load impact would have been added to any other day of the week in that month, the resulting forecast would have been lower because the non-weather related load in such days is lower compared to Wednesdays. In practice, extreme weather may occur on any day of the month, and Hydro One must take this fact into account in calculating monthly peak in order to accurately forecast the monthly peaks that drive the collection of transmission revenue.

c) Hydro One is following the same approach to the treatment of DR as in its previous Application (EB-2016-0160), which is that incremental DR over the forecast period is assumed to be 0. Consequently, for simplicity, Hydro One does not add impact of DR to base-year weather-corrected actual and does not deduct the same amount back over the forecast period.

This same issue was raised by VECC in EB-2016-0160 and addressed in Hydro One's Reply Argument. As stated in Hydro One's Reply Argument, our weather correction methodology accounts for the impact of DR programs. Consequently, adding the load impact of DR to the base year weather corrected actual load leads to a double-counting of DR impact so that, over the forecast period, it should be deducted back to have a realistic forecast. At page 67 of the OEB's Decision and Order (dated October 11, 2017) in EB-2016-0160, the OEB approved Hydro One's load forecast methodology and noted that there was no need to revisit the treatment of DR programs in Hydro One's next transmission rates proceeding.

VECC INTERROGATORY #32

Reference:

E-03-01 p. 8 H-01-02Attachment 11

Interrogatory:

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

Response:

a) Yes, all of the 2018 values reported in the initial Application were based on 2018 actual data, please see response to Exhibit I, Tab 10, Schedule VECC-22, part (a).

b) Please see the following table for the requested information.

Survey of Ontario GDP Forecast (annual growth rate in %)

	2017	2018	2019	2020	2021	2022
Global Insight (Jun 2019)	2.8	2.2	1.5	1.5	1.8	1.9
Conference Board (Nov 2018)	2.8	2.2	1.2	2.0	1.8	1.8
U of T (Apr 2019)	2.8	2.2	1.8	2.4	2.2	2.2
C4SE (Mar 2019)	2.8	2.4	1.6	1.6	1.9	2.1
CIBC (Jan 2019)	2.8	2.1	2.0	1.4		
BMO (July 2019)	2.8	2.2	1.6	1.7		
RBC (Jun 2019)	2.8	2.2	1.4	1.6		
Scotia (Apr 2019)	2.8	1.8	1.7	1.7		
TD (Jun 2019)	2.7	2.2	1.3	1.4		
Desjardins (Jun 2019)	2.8	2.2	1.5	1.7		
Central 1 (May 2019)	2.8	2.3	1.6	1.5	1.7	
National Bank (Jul 2019)	2.8	2.2	1.4	1.8		
Laurentian Bank (Sep 2018)	2.7	1.9	1.7	1.8		
Average	**2.8**	**2.2**	**1.6**	**1.7**	**1.9**	**2.0**

Survey of Ontario Housing Starts Forecast (in 000's)

	2017	2018	2019	2020	2021	2022
Global Insight (Jun 2019)	80.1	79.4	72.3	67.7	63.0	61.4
Conference Board (Nov 2018)	79.0	78.7	70.9	77.4	79.0	79.9
U of T (Apr 2019)	75.0	79.1	78.7	67.1	69.8	70.7
C4SE (Mar 2019)	79.1	78.7	72.0	70.2	71.5	72.4
CIBC (Jan 2019)	79.1	78.0	68.0	63.0		
BMO (July 2019)	80.1	79.4	73.5	72.0		
RBC (Jun 2019)	79.1	78.7	73.1	71.0		
Scotia (Apr 2019)	79.0	79.0	73.0	72.0		
TD (Jun 2019)	80.1	79.4	69.4	73.9		
Desjardins (Jun 2019)	79.1	78.7	68.4	70.0		
Central 1 (May 2019)	79.1	78.7	71.0	70.8	75.2	
National Bank (Jul 2019)	79.0	78.7	68.6	65.0		
Laurentian Bank (Sep 2018)	79.1	76.0	73.0	72.0		
Average	**79.0**	**78.7**	**71.7**	**70.2**	**71.7**	**71.1**

Forecast updated on July 6, 2019

VECC INTERROGATORY #33

Reference:
E-03-01 p. 8 H-01-02-11

Interrogatory:
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.

Response:
a) Please see the response to Exhibit I, Tab 10, Schedule VECC-24 part (h) subpart (i).

b) Please see the response to Exhibit I, Tab 10, Schedule VECC-24 part (h) subpart (i).

c) The historical peak saving results used for the purpose of the CDM variance account have no impact on growth rates calculated by the load forecasting model because the forecasted growth rates are based on energy models, and not dependent on the actual peak saving results. Hydro One adds the energy impact of CDM to actual load to arrive at gross load used for developing the growth rates that drive the test year gross load forecast.

Witness: Bijan Alagheband, Henry Andre

VECC INTERROGATORY #34

Reference:

E-03-01p. 8

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)

Interrogatory:

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?

Response:

a) Confirmed.

b) The IESO's interim framework plan set out the budget and target for the programs offering from April 2019 to December 2020; which is expected to achieve 189 MW of demand savings. However, the updated CDM savings for 2021 and beyond is not yet available from the Ministry of Energy and the IESO.

Hydro One's preliminary estimation of the CDM peak impact due to the IESO's interim framework plan is 50 MW less than the peak saving forecast used for the load forecast in 2020 based on our methodology (details provide in the table below). The interim framework plan did not develop the target for 2021 and beyond, therefore an estimation of the impact for 2021 to 2022 cannot be provided at this time.

Formula		2015	2016	2017	2018	2019	2020	2021	2022	Note
(1)	Province wide 2015-2017 CFF program	233	420	663						Source: 2017 Final verifeid annual LDC CDM program results.xls- tab "province wide saving persistence",cell DT517-DV517
(2)	LTEP EE program savings (historical and future programs)	1,528	1,662	1,575	1,752	2,022	2,321	2,357	2,470	impact from 2006-2022 EE programs
(3)=(1)/(2)	% of 2015-2017 EE program / all EE pro	15%	25%	42%						implementation year, therefore using the share of CFF savings to all EE savings to
(4)=42%*(2)	Estimated 2015-2020 CFF program savings for 2018-2022				737	851	977	992	1,040	applied 42% to the LTEP all EE savings 2018-2020.
(5)	2020 vs 2018 incremnetal peak savings						239			977mw(2020)-737MW (2018)
(6)	IESO interim framwork program plan (IFPP) peak target 2019-2020						189			http://www.ieso.ca/-/media/Files/IESO/Document-Library/Interim-
(7)=(5)-(6)	Difference of forecasted and IFPP peak incremental savigns						50			239MW-189MW

Hydro One notes that the IESO's interim framework also indicates that it is planning to refocus its CDM programs and increase their efficiency. Since the IESO's main concern is system peak, this would imply that the peak impact of future CDM programs could be greater than what is assumed in this Application. At the present time, such additional peak impact of future programs is not known.

VECC INTERROGATORY #35

Reference:
F-01-01p. 5

Interrogatory:

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

Response:

a) In the current application, the funding envelope for the 2020 Test Year is 4.7% lower than the 2018 approved amount. This demonstrates that Hydro One is asking for a lower OM&A funding envelope. Furthermore, Hydro One's Sustainment OM&A is 6.6% lower than 2018 actuals. If Hydro One was required to make an additional 5% reduction to its proposed 2020 OM&A budget, the following Sustainment OM&A programs would be reduced, thereby increasing safety or reliability risk:
   - Vegetation maintenance on non-critical 115 kV corridors would be deferred. Corridors would begin to become overgrown with vegetation and dead, diseased or dying trees would not be removed. This would increase vegetation related

outages and result in increased system and customer interruptions. Furthermore the future cost to clear these sections of right-of-way would increase as described in Interrogatory I-12-AMPCO-52.

- There would be reductions in transformer maintenance, leak reduction programs, breaker refurbishment, breaker preventive maintenance and switch preventive maintenance. These reductions would impact system and customer reliability and power quality.
- Condition assessments on overhead lines asset would be deferred and so the assets requiring condition assessment would not be addressed in a timely manner. There would be a higher safety and reliability risk due to the inability to identify and address existing defects and end of life assets.

b) Corporate Management, Finance, Human Resources, Corporate Affairs, General Counsel and Secretariat and Regulatory Affairs are not considered programs as they are Corporate Groups which are allocated to Transmission/ Distribution/ OM&A/ Capital based on a corporate cost allocation methodology which is reviewed by Black and Veatch. The allocation methodology is discussed in detail in Exhibit F, Tab 2, Schedule 6 Attachment 1. These Corporate groups do not directly affect safety or reliability of service in their functions, but do indirectly have an impact as they promote a culture of safety and reliability through their interactions with the work program and by enabling safety and reliability data to be available and shared across stakeholder groups.

As noted in Exhibit F, Tab 2, Schedule 2, significant commitments to reductions in overhead functions have already been implemented and included in this application.

Work performed under the Transmission Standards program funds the maintenance and update of technical standards, procedures and work instructions. These affect safety and reliability of service through the definition of repeatable reference documents to ensure the safe design, development and maintenance of physical assets, including incorporation of key safety aspects such as limits of approach and control zones and appropriate maintenance requirements. Research Development and Demonstration programs fund research into the management of physical assets, including providing insights and best practices related to work methods, asset analytics, maintenance procedures and innovative new designs which contribute to the safe and reliable operation of assets.

VECC INTERROGATORY #36

Reference:
F-01-03p. 10

Interrogatory:
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?

Response:
a) As provided in Exhibit B-1-1 TSP Section 3.1.2.1, there are currently 6,267 components identified that require sampling, retro-fill or replacement.

b) Hydro One's Environmental management program addresses PCB remediation through sampling and retrofilling. The proposed number of candidates for sampling and retrofill are shown below. PCB capital replacement is described in ISDs SR-03 to SR-07.

	2020	2021	2022	2023	2024
Retrofill (units)	420	1,083	1,091	1,181	241
Sampling (units)	3,000	1,200			

c) Table 3 shows the actual historical cost and forecast Bridge year cost as well as the forecast Test year. Complete remediation would be done in 2024. As explained on Page 11 Section 3.1.2.1.

Witness: Donna Jablonsky

VECC INTERROGATORY #37

Reference:
F-1-5

Interrogatory:
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.

Response:
a) No, this is a recurring investment under Operations OM&A.

b) No, please see F-01-05 page 6 line 20 to page 7 line 19 for more investment details.

VECC INTERROGATORY #38

Reference:
F-01-07p. 4

Interrogatory:

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?

Response:

a) Please see TSP Section 1.6, 1.6.2.2 Overview of Productivity Savings, for a detailed description. Additional information on defining initiatives is described in interrogatory response I-01-OEB-002, part d).

b) The achievement of corporate productivity savings against committed targets is included as a quantified component of Management Short Term and Long Term incentive programs.

Witness: Andrew Spencer, Joel Jodoin

VECC INTERROGATORY #39

Reference:
F-02-02p. 2

Interrogatory:

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.

Response:

a) Please see Exhibit F, Tab 2, Schedule 2 Table 4 for more detailed summary of changes between 2015 Actual and 2019 Forecast. The primary driver of the variance is increase in costs that are allocated to Shareholder and do not impact Transmission revenue requirement (EVP Strategy Office, Investor Relations) as well as the inclusion of Ombudsman and LTD Costs. Additionally higher costs (relative to 2015) for executive compensation in General Counsel - VP and CFO Office have been considered in the Forecast. As shown in Table 5, the amount allocated to Transmission has decreased from $2.8 million in 2015, to $2.4 million in 2020.

b) The table 1 costs referenced would not change as a result of "legislated restrictions on compensation recovery" as table 1 represents the total Common Corporate Functions and Services OM&A. Recovery principles would not change the total costs.

Witness: Joel Jodoin

c) Corporate Management costs have increased due to the items noted in part a) above and the allocation to transmission has declined in 2019 and 2020 since 2015. This is a correct interpretation.

The decrease in allocation to Transmission has been as a result of more costs being allocated to the Shareholder. Table 1 (2019) and Table 2 (2020) from Exhibit F, Tab 2, Schedule 6 show the Corporate Management allocations across all business units.

VECC INTERROGATORY #40

Reference:

F-02-02p. 14

Interrogatory:

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.

Response:

a) The Human Resources (HR) function has increased in size from 2015 to 2019 in part to consolidate HR related functions from other teams outside of HR and to provide enhanced programs to support the business.

The headcount from 2015 to 2019 has increased by 37 which is largely attributable to the following:

- Internal transfers from the Rehab and Disability Management and Internal Communications functions. These are not net new roles, as corresponding headcount reductions occurred within the Health & Safety and Communications teams.
- Increasing the size of the Change Management function due to the renewed focus on change management initiatives intended to maximize the value of corporate change initiatives.
- The addition of a compensation function to support a renewed focus on incentive based compensation to drive a high performance culture.
- Increasing the scope of the HR Reporting function to include a new HR Analytics focus to enhance metrics to inform business decisions and develop a workforce planning program.
- Enhancing the HR Business Partner function by creating an all front facing team to better service Lines of Businesses throughout the province (especially outside the GTA) and operationalize various HR programs.
- Increasing the scope of the Talent Management function to include performance management and organizational design.

- The creation and enhancement of the HR Shared Service team to operationalize current and future technology projects and other HR initiatives, and to centralize administrative tasks within HR into one function.

Hydro One discloses compensation information in the Management Information Circular and in accordance with the disclosure requirements as per Bill 2 Urgent Priorities Act, 2018. In addition, compensation information is available in the benchmarking studies by Mercer (F-04-01-02) and Willis Towers Watson (F-04-01-01 and F-04-01-3). The Mercer study in particular includes benchmarking for the HR Manager/Consultant role, which is 21% below market on a Total Compensation basis, (as noted on page 17 of the report) meaning it is compensated significantly less relative to the peer group.

HR salaries have increased in accordance with corporate guidelines for merit pay.

The overall increase from $6.8 million in 2015 to $12.2 million in 2020 in HR Costs allocated to Transmission, as per Exhibit F, Tab 2, Schedule 2 page 14, is in part attributed to the FTE increase as noted above. The remainder encompasses budgetary increases to support the increasing scope of the HR function. For those functions that were transferred internally the corresponding reductions occurred with the sending teams (i.e. health and safety and communications).

VECC INTERROGATORY #41

Reference:
F-03-01p. 7

Interrogatory:

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

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

c) Please provide the annual cost of this contract.

Response:

a) The BGIS agreement took effect on January 1, 2015.

b) The following list outlines the services provided by BGIS which accumulate to a total of $33.6M in 2018.
   - Facilities Management & Administration - $4.6M
   - Grass Cutting & Grounds Maintenance - $4.4M
   - Site Inspections - $1.2M
   - Janitorial & Waste Removal - $4.9M
   - Moves & Accommodations - $1.0M
   - Preventative Maintenance - $4.1M
   - Corrective Repairs - $7.2M
   - Snow Removal - $4.6M

   $24.0 million or approximately 69% of the overall costs listed above are allocated to transmission OM&A.

   As noted above in, BGIS provides a series of services which benefits multiple lines of business and which is spread across the various OM&A categories As such, a comparison of the actual costs in b) to the OEB-approved values for 2018 is not possible. Additionally, the OEB approves OM&A expenditures at the envelope level, not the category level, making the comparison not possible.

c) The annual cost of this contract is approximately $30.4 million (based on 3 year average). This value specifically pertains to the Operations and Maintenance of facilities and takes into account the annual CPI increase, building additions/removals and/or changes to maintenance requirements.

VECC INTERROGATORY #42

Reference:

F-04-01p. 13

Interrogatory:

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.

Response:

a) Please see Exhibit I, Tab 07, Schedule SEC-50.

Witness: Sabrin Lila

VECC INTERROGATORY #43

Reference:
G-01-01p. 3-6

Interrogatory:

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.

Response:

a) No, Hydro One has not carried out an analysis or study of the change in cost of long and medium term debt (new and old issue yields) pre and post its initial public offering.

b) Please see tables below for the annual historical yields from 2012 to 2018.

Please note that Government of Canada historical yields shown in the tables are the daily average of benchmark actual mid-market closing yields for the 5, 10 and 30 (long-term) year bonds. This data was obtained from the Bank of Canada website by querying the V39053 (5-year), V39055 (10-year) and V39056 (long-term) data series. Hydro One Spreads are a weekly average obtained from one of the Company's MTN dealers.

	2012			2013		
	5-year	**10-year**	**30-year**	**5-year**	**10-year**	**30-year**
Government of Canada	1.38%	1.87%	2.45%	1.62%	2.26%	2.83%
Hydro One Spread	0.83%	1.13%	1.48%	0.76%	1.06%	1.42%
Historical Average Hydro One Yield	2.21%	3.00%	3.93%	2.38%	3.32%	4.25%

	2014			2015		
	5-year	**10-year**	**30-year**	**5-year**	**10-year**	**30-year**
Government of Canada	1.58%	2.23%	2.77%	0.85%	1.52%	2.19%
Hydro One Spread	0.74%	1.02%	1.37%	0.89%	1.16%	1.61%
Historical Average Hydro One Yield	2.32%	3.25%	4.14%	1.74%	2.68%	3.80%

	2016			2017		
	5-year	**10-year**	**30-year**	**5-year**	**10-year**	**30-year**
Government of Canada	0.73%	1.25%	1.92%	1.36%	1.78%	2.28%
Hydro One Spread	0.98%	1.28%	1.73%	0.68%	0.94%	1.38%
Historical Average Hydro One Yield	1.71%	2.53%	3.65%	2.04%	2.72%	3.66%

	2018			2019 (January 1 to June 30)		
	5-year	**10-year**	**30-year**	**5-year**	**10-year**	**30-year**
Government of Canada	2.15%	2.28%	2.36%	1.63%	1.74%	2.00%
Hydro One Spread	0.80%	1.06%	1.44%	0.97%	1.32%	1.66%
Historical Average Hydro One Yield	2.95%	3.34%	3.80%	2.60%	3.06%	3.66%

VECC INTERROGATORY #44

Reference:

H-01-01 p.4H-01-05-01

Interrogatory:

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.

Response:

	2016	2017	2018
Forecast Export Revenues	31,700,000	39,200,000	40,100,000
Actual Export Revenues (Note 1)	41,446,764	35,426,132	35,381,429

Note 1 - The actual revenues are as per the monthly IESO invoice. Since the IESO invoice is received a month in arrears, an estimate based on prior years is used as an accrual in the month and the applicable adjusting entry is recorded in the following month. On a net basis, the yearly difference between actual and accrual is not material as the accrual is only present in December.

Witness: Samir Chhelavda

VECC INTERROGATORY #45

Reference:

H-01-02-11

EB-2016-0160, HON IRR VECC 27

Interrogatory:

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.

Response:

a) i. Please see the response to Exhibit I, Tab 10, Schedule VECC-24 part (d), the IESO 2006-2017 Savings & Persistence Table.

   ii. This information has been provided in excel format, please refer to Attachment 1 of this response.

iii. The detail calculations for dollar variance by billing determinants are included in Attachment 1 of this response.

b) Confirmed.

c) Not applicable based on response to part (b) above.

d) The requested information is already reflected in Table 2 of Exhibit H, Tab 1, Schedule 2, Attachment 11 in the Update Application filed in June 2019.

Peak Demand Saving (MW)

	2016	2017
EE	1662	1575
Codes and Standards	505	525
Total	2167	2099

Generator level	2016	2017
ind-TX	115	147
ALL LDCs	2,052	1,952
Total	2,167	2,099

OPA Loss Factor Assumption

	2016	2017
distribution	0.065	0.065
transmission	0.025	0.025
Total	0.09	0.09

Generator level MW	2016	2017
ind-TX	112	144
ALL LDCs	1,927	1,833
Total	2,039	1,976

I-10-VECC-45 a(ii)

variance in KW

Month	LF assumption at the end use level (KW)			EE monthly profile used in LF		IESO EE saving EMV resutls (KW)			variance in KW (Dif of dif)
	2016	2017	dif (2017 vs 2016)	2016	2017	2016	2017	dif (2017 vs 2016)	2017
	A	B	C= B-A			D	E	F= E-D	F-C
1	1,433,588	1,447,218	13,630	0.703098233	0.732290385	1,766,438	1,902,247	135,809	122,179
2	1,419,005	1,431,228	12,223	0.6959462	0.724199799	1,748,469	1,881,230	132,761	120,537
3	1,312,901	1,325,258	12,357	0.643908009	0.670578944	1,617,730	1,741,941	124,211	111,854
4	1,342,374	1,343,303	929	0.658362855	0.679709696	1,654,046	1,765,660	111,613	110,684
5	1,417,979	1,418,906	927	0.695442939	0.717964835	1,747,205	1,865,034	117,829	116,901
6	1,874,071	1,876,242	2,171	0.919131829	0.949376204	2,309,192	2,466,163	156,971	154,800
7	2,038,958	1,976,289	(62,669)	1	1	2,512,363	2,597,667	85,305	147,973
8	1,855,321	1,860,329	5,009	0.909935719	0.941324401	2,286,088	2,445,247	159,159	154,150
9	1,681,441	1,684,207	2,766	0.824657241	0.852206779	2,071,838	2,213,750	141,912	139,146
10	1,326,777	1,331,972	5,196	0.650713035	0.67397638	1,634,827	1,750,766	115,939	110,743
11	1,353,137	1,361,789	8,652	0.663641321	0.689063398	1,667,308	1,789,957	122,650	113,998
12	1,439,403	1,451,722	12,319	0.705950388	0.734569584	1,773,603	1,908,167	134,564	122,245

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$ Impact calculation

UTR and Ratio of CD used for the $ calculation

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	3.66	0.87	2.02	
FNEI Allocation Factor	0.00398	0.00413	0.00413	
CNPI Allocation Factor	0.00281	0.00291	0.00291	
GLPT Allocation Factor	0.02554	0.02648	0.02648	
H1N Allocation Factor	0.93219	0.96648	0.96648	
B2MLP Allocation Factor	0.03548	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

2016

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	3.52	0.88	2.13	
FNEI Allocation Factor	0.00409	0.00425	0.00425	
CNPI Allocation Factor	0.00300	0.00312	0.00312	
H1N SSM Allocation Factor	0.02620	0.02724	0.02724	
H1N Allocation Factor	0.92828	0.96539	0.96539	
B2MLP Allocation Factor	0.03843	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

2017

Uniform Transmission Rates and Revenue Disbursement Allocators
(Effective for Period January 1, 2017 to December 31, 2017) (Implementation for November1, 2017)

Uniform Transmission Rates ($/kW) / **Ratio of Charge Determinants to Ontario Peak (12-month aveerage peak in MW)**

Charge Determinants	2016	2017	TX Charge Determinant	2016	2017
Network	3.66	3.52	Network Connection	0.93219	0.92828
Line Connection	0.87	0.88	Line Connection	0.96648	0.96539
Transformation Connection	2.02	2.13	Transformation Connection	0.96648	0.96539

Note. The new rates for 2017 were not implemented till November 2017. The balance was carried to 2018.

Month	Uniform Transmission Rates ($/kW)			Ratio of Charge Determinants to Ontario Peak (12-month aveerage peak in MW)			HONI Uniform Transmission Rates ($/kW)			Total
	Network Connection	Line Connection	Transformation Connection	Network Connection	Line Connection	Transformation Connection	Network Connection	Line Connection	Transformation Connection	
JAN	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
FEB	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
MAR	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
APR	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
MAY	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
JUN	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
JUL	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
AUG	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
SEP	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
OCT	3.66	0.87	2.02	0.93219	0.96648	0.96648	3.41	0.84	1.95	6.20
NOV	3.52	0.88	2.13	0.92828	0.96539	0.96539	3.27	0.85	2.06	6.17
DEC	3.52	0.88	2.13	0.92828	0.96539	0.96539	3.27	0.85	2.06	6.17

Varince in $

Month	EE Variance KW	HONI Uniform Transmission Rates ($/kW)			Variance in $			
		Network Connection	Line Connection	Transformation Connection	Network Connection	Line Connection	Transformation Connection	Variance Total $
JAN	122,179	3.41	0.84	1.95	416,852.13	102,733	238,529	758,114
FEB	120,537	3.41	0.84	1.95	411,251.61	101,352	235,324	747,928
MAR	111,854	3.41	0.84	1.95	381,624.49	94,051	218,371	694,046
APR	110,684	3.41	0.84	1.95	377,634.90	93,068	216,088	686,791
MAY	116,901	3.41	0.84	1.95	398,846.18	98,295	228,225	725,367
JUN	154,800	3.41	0.84	1.95	528,148.92	130,162	302,214	960,525
JUL	147,973	3.41	0.84	1.95	504,856.92	124,421	288,886	918,165
AUG	154,150	3.41	0.84	1.95	525,932.16	129,615	300,946	956,493
SEP	139,146	3.41	0.84	1.95	474,739.65	116,999	271,653	863,391
OCT	110,743	3.41	0.84	1.95	377,835.87	93,117	216,203	687,156
NOV	113,998	3.27	0.85	2.06	372,492.94	96,846	234,411	703,750
DEC	122,245	3.27	0.85	2.06	399,441.11	103,852	251,370	754,664
Total	1,525,211				5,169,657	1,284,512	3,002,221	9,456,390

VECC INTERROGATORY #46

Reference:
I1-01-02p. 8

Interrogatory:
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?

Response:
a) The Wholesale Revenue Metering assets account for approximately 0.002% of the Transformation Connection assets for 2020.

b) As shown in Exhibit I1, Tab 5, Schedule 1, Table 1, the 2020 Wholesale Metering Service revenue is forecasted to be $0.1M, which is 0.02% of the total costs allocated to the Transformation Connection rate pool ($456.5M).

VECC INTERROGATORY #47

Reference:

I1-01-02p. 2

Interrogatory:

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.

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

Response:

Investments that are forecast to be in-service in 2020 are functionalized based on the anticipated function and normal operating condition of the asset in the future.

For system renewal investments, in-service additions are typically allocated based on the current functional category of the line or station, consistent with Exhibit I1, Tab 2, Schedules 1 and 2.

For system service and system access investments, in-service additions are allocated to functional categories based on the anticipated future use of the new or enhanced facility.

VECC INTERROGATORY #48

Reference:
I1-02-01

Interrogatory:

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.

Response:

a) A list of new transmission line assets that were not included in proceeding EB-2016-0160 is provided in Table 1 below.

b) A list of the transmission line assets whose functional category has changed from that in EB-2016-0160 is provided in Table 2 below. The majority of the changes in functional category are a result of the OEB's Decision in proceeding EB-2011-0043, where the definition of Network asset was expanded to include certain assets previously captured under the definition of a Line Connection asset.

Table 1 – List of New Transmission Lines

Operation Designation	Sect.	From	To	Functional Category	Explanation
A4L	13	Namewaminikan JCT	Jellicoe DS #3 JCT	LC	Generation Connection: Namewaminikan CGS
A4L	14	Namewaminikan JCT	Namewaminikan CGS	LC	Generation Connection: Namewaminikan CGS
A5RK	8	A5RK STR O7 JCT	Overbrook TS	LC	EB-2016-0160 Project D10: Riverdale Junction to Overbrook TS
B20P	8	Bruce A TS	Bruce HW Plant B TS	LC	Reconfiguration of normal operating system
B24P	8	Bruce A TS	Bruce HW Plant B TS	LC	Reconfiguration of normal operating system
B4V	9	Southgate JCT	GV3 WF JCT	DFL	Database cleanup
B4V	10	Southgate JCT	Southgate CGS	LC	Generation Connection: Southgate CGS
B543TC	1	Bowmanville SS	Clarington JCT	N	EB-2016-0160 Project D01: Clarington TS
B543TC	2	Clarington JCT	Cherrywood TS	N	EB-2016-0160 Project D01: Clarington TS
B543TC	3	Clarington JCT	Clarington TS	N	EB-2016-0160 Project D01: Clarington TS
B5C	1	Burlington TS	Harper's JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	2	Harper's JCT	Puslinch JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	3	Puslinch JCT	Arlen MTS JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	4	Arlen MTS JCT	Hanlon JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	5	Hanlon JCT	Cedar TS	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	6	Harper's JCT	Westover JCT	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	7	Westover JCT	Westover A JCT	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	8	Westover A JCT	Enbrg Westover S CTS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	9	Westover A JCT	Enbrg Westover N CTS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	10	Puslinch JCT	Puslinch DS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	11	Arlen MTS JCT	Arlen MTS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B5C	12	Hanlon JCT	Hanlon TS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B6C	1	Burlington TS	Harper's JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement

Operation Designation	Sect.	From	To	Functional Category	Explanation
B6C	2	Harper's JCT	Puslinch JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B6C	3	Puslinch JCT	Arlen MTS JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B6C	4	Arlen MTS JCT	Hanlon JCT	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B6C	5	Hanlon JCT	Cedar TS	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B6C	6	Puslinch JCT	Puslinch DS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B6C	7	Arlen MTS JCT	Arlen MTS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B6C	8	Hanlon JCT	Hanlon TS	LC	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
B88H	1	Brown Hill TS	York EnergyCentr JCT	DFL	EB-2016-0160 Project D07: York Region
B88H	2	York EnergyCentr JCT	Holland Marsh JCT	DFL	EB-2016-0160 Project D07: York Region
B88H	3	Holland Marsh JCT	Holland TS	DFL	EB-2016-0160 Project D07: York Region
B88H	4	Holland TS	Armitage TS	DFL	EB-2016-0160 Project D07: York Region
B88H	5	York EnergyCentr JCT	York EnergyCentr CGS	LC	EB-2016-0160 Project D07: York Region
B89H	1	Brown Hill TS	York EnergyCentr JCT	DFL	EB-2016-0160 Project D07: York Region
B89H	2	York EnergyCentr JCT	Holland Marsh JCT	DFL	EB-2016-0160 Project D07: York Region
B89H	3	Holland Marsh JCT	Holland TS	DFL	EB-2016-0160 Project D07: York Region
B89H	4	Holland TS	Armitage TS	DFL	EB-2016-0160 Project D07: York Region
B89H	5	York EnergyCentr JCT	York EnergyCentr CGS	LC	EB-2016-0160 Project D07: York Region
C21J	5	Leamington JCT	Sandwich JCT	DFL	EB-2016-0160 Project D14: Supply to Essex County Transmission Reinforcement
C22J	5	Leamington JCT	Sandwich JCT	DFL	EB-2016-0160 Project D14: Supply to Essex County Transmission Reinforcement
C23Z	9	Belle River JCT #2	Sandwich JCT	DFL	Generation Connection: Belle River CGS
C23Z	10	Belle River JCT #2	Belle River CSS	LC	Generation Connection: Belle River CGS
C7BM	26	Bellman JCT	NQL1 B JCT	DFL	Database cleanup
D6T	8	P Sutherland Sr JCT	Otter Rapids SS	LC	Generation Connection: Peter Sutherland Senior GS

Operation Designation	Sect.	From	To	Functional Category	Explanation
D6T	9	P Sutherland Sr JCT	P Sutherland Sr SYD	LC	Generation Connection: Peter Sutherland Senior GS
E1C	17	Golden Patricia JCT	Golden Patricia JCT	LC	Database cleanup
H82V	1	Holland TS	Holland JCT	DFL	EB-2016-0160 Project D07: York Region
H82V	2	Holland JCT	Vaughan #4 JCT	DFL	EB-2016-0160 Project D07: York Region
H82V	3	Vaughan #4 JCT	Woodbridge JCT	DFL	EB-2016-0160 Project D07: York Region
H82V	4	Woodbridge JCT	Claireville TS	DFL	EB-2016-0160 Project D07: York Region
H82V	5	Vaughan #4 JCT	Vaughan MTS #4	LC	EB-2016-0160 Project D07: York Region
H83V	1	Holland TS	Holland JCT	DFL	EB-2016-0160 Project D07: York Region
H83V	2	Holland JCT	Vaughan #4 JCT	DFL	EB-2016-0160 Project D07: York Region
H83V	3	Vaughan #4 JCT	Woodbridge JCT	DFL	EB-2016-0160 Project D07: York Region
H83V	4	Woodbridge JCT	Claireville TS	DFL	EB-2016-0160 Project D07: York Region
H83V	5	Vaughan #4 JCT	Vaughan MTS #4	LC	EB-2016-0160 Project D07: York Region
H9W	1	Beach TS	West Lincoln JCT	LC	Generation Connection: West Lincoln CGS
H9W	2	West Lincoln JCT	West Lincoln CSS	LC	Generation Connection: West Lincoln CGS
HIGHFAL2	1	Anjigami CTS	Anjigami JCT	N	Reconfiguration of normal operating system
HIGHFAL2	3	Anjigami JCT	Wawa TS	LC	Reconfiguration of normal operating system
HLNGWTH1	1	Anjigami CTS	Anjigami JCT #2	N	Reconfiguration of normal operating system
HLNGWTH1	3	Anjigami JCT #2	Wawa TS	LC	Reconfiguration of normal operating system
IDLE28	1	Kent TS	Kent JCT	OTHER	Reconfiguration of normal operating system
IDLE28	2	Kent JCT	T9K T#207 JCT	OTHER	Reconfiguration of normal operating system
IDLE29	1	Holland Marsh JCT	Holland JCT	OTHER	EB-2016-0160 Project D07: York Region
IDLE30	1	Holland Marsh JCT	Holland JCT	OTHER	EB-2016-0160 Project D07: York Region
K24F	2	Rainy River Gold JCT	Fort Frances TS	DFL	Customer Connection: Rainy River Gold CTS
K24F	3	Rainy River Gold JCT	Rainy River Gold CSS	LC	Customer Connection: Rainy River Gold CTS

Operation Designation	Sect.	From	To	Functional Category	Explanation
L15	1	Leaside TS	Bayview JCT	LC	Reconfiguration of normal operating system
L15	2	Bayview JCT	Balfour JCT	LC	Reconfiguration of normal operating system
L15	3	Balfour JCT	Bridgman JCT	LC	Reconfiguration of normal operating system
L15	4	Bridgman JCT	Bridgman TS	LC	Reconfiguration of normal operating system
L18W	1	Leaside TS	Leaside TS	DFL	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L18W	3	Bayview JCT	Birch JCT	DFL	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L18W	4	Birch JCT	Bridgman JCT	DFL	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L18W	5	Bridgman JCT	Bartlett JCT	DFL	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L18W	6	Bartlett JCT	Wiltshire TS	DFL	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L18W	7	Bridgman JCT	Bridgman TS	LC	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L18W	8	Bartlett JCT	Bartlett JCT	LC	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L18W	9	Bartlett JCT	Dufferin TS	LC	EB-2014-0140 Project D4: Midtown Transmission Reinforcement
L28C	4	GSPC JCT	Lynwood JCT	DFL	Generation Connection: GSPC CGS
L29C	6	North Kent 1 JCT	Lynwood JCT	DFL	Generation Coonection: North Kent CGS
L29C	7	North Kent 1 JCT	North Kent 1 CGS	LC	Generation Coonection: North Kent CGS
M20D	17	Galt South JCT	Galt JCT	DFL	EB-2016-0160 Project D06: Galt Junction
M21D	19	Galt North JCT	Kitchener #8 JCT	DFL	EB-2016-0160 Project D06: Galt Junction
M2W	27	Animki JCT	White River DS	LC	Database cleanup
M31	3	Espanola A JCT	Eddy Tap A JCT	LC	Database cleanup
M31	4	S2B-M31 JCT	Espanola A JCT	OTHER	Database cleanup
P7B	2	P7B STR 320 JCT	Birch TS	N	Reconfiguration of normal operating system
R19TH	11	Churchill MeadowsJCT	Churchill Meadows TS	LC	Database cleanup
S2B	34	Blind River TS JCT	Blind River TS	OTHER	Database cleanup
S2B	42	S2B-M31 JCT	Baldwin JCT	LC	Reconfiguration of normal operating system

Operation Designation	Sect.	From	To	Functional Category	Explanation
S3S	4	S3S_S4S STR 8 JCT	Kapuskasing R Jct	OTHER	Reconfiguration of normal operating system
T1B	10	Red Rock CGS JCT	Cobden JCT	LC	Reconfiguration of normal operating system
T1B	11	Red Rock CGS JCT	Red Rock CGS	LC	Reconfiguration of normal operating system
T22C	1	Chats Falls SS	Marine JCT	DFL	EB-2016-0160 Project D01: Clarington TS
T22C	2	Marine JCT	Clarington TS	DFL	EB-2016-0160 Project D01: Clarington TS
T22C	3	Marine JCT	Otonabee TS	LC	EB-2016-0160 Project D01: Clarington TS
T28C	1	Clarington TS	Duffin JCT	N	EB-2016-0160 Project D01: Clarington TS
T28C	2	Duffin JCT	Cherrywood TS	N	EB-2016-0160 Project D01: Clarington TS
T29C	1	Clarington TS	Wilson JCT	DFL	EB-2016-0160 Project D01: Clarington TS
T29C	2	Wilson JCT	Whitby JCT	DFL	EB-2016-0160 Project D01: Clarington TS
T29C	3	Whitby JCT	Cherrywood TS	DFL	EB-2016-0160 Project D01: Clarington TS
T29C	4	Wilson JCT	Wilson TS	LC	EB-2016-0160 Project D01: Clarington TS
T29C	5	Whitby JCT	Whitby TS	LC	EB-2016-0160 Project D01: Clarington TS
T33E	1	Almonte TS	Almonte TS	LC	EB-2016-0160 Project D01: Clarington TS
T33E	2	Almonte TS	Clarington TS	DFL	EB-2016-0160 Project D01: Clarington TS
T33E	3	Almonte TS	Almonte TS	DFL	EB-2016-0160 Project D01: Clarington TS
T9K	3	T9K T#80 JCT	T9K T#207 JCT	OTHER	Reconfiguration of normal operating system
X534N	1	Lennox TS	Napanee CSS	N	Generation Connection: Napanee CGS
X538N	1	Lennox TS	Napanee CSS	N	Generation Connection: Napanee CGS
Z1E	10	Windsor Airport JCT	Jefferson JCT	DFL	Generation Connection: Windsor Airport CGS
Z1E	11	Windsor Airport JCT	Windsor Airport CGS	LC	Generation Connection: Windsor Airport CGS
Z1E	12	Jefferson JCT	Jefferson JCT	LC	Reconfiguration of normal operating system
Z7E	10	Jefferson JCT	Jefferson JCT	LC	Reconfiguration of normal operating system

Witness: Clement Li, Henry Andre

Table 2 – List of Transmission Lines with Functional Category Changes

Operation Designation	Sect.	From	To	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
B12	1	Burlington TS	Dundas #2 JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B12	2	Dundas #2 JCT	Horning Mountain JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B12	3	Horning Mountain JCT	Alford JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B12	4	Alford JCT	Powerline JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B12	8	Powerline JCT	Brant TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B13	1	Burlington TS	Dundas #2 JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B13	2	Dundas #2 JCT	Horning Mountain JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B13	3	Horning Mountain JCT	Alford JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B13	4	Alford JCT	Powerline JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B13	8	Powerline JCT	Brant TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B8W	1	Brant TS	Brant JCT	DFL	OTHER	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B8W	2	Brant TS	Brant JCT	DFL	OTHER	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS

Operation Designation	Sect.	From	To	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
B8W	3	Brant JCT	Toyota Woodstock JCT	DFL	OTHER	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B8W	6	Toyota Woodstock JCT	Commerce Way JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B8W	8	Commerce Way JCT	Commerce Way TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
B8W	9	Commerce Way JCT	Commerce Way TS	DFL	OTHER	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
C14L	1	Cherrywood TS	Scarboro JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C14L	2	Scarboro JCT	Bermondsey TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C14L	3	Bermondsey TS	Leaside TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C15L	1	Cherrywood TS	Sheppard TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C15L	2	Sheppard TS	Scarboro JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C15L	3	Scarboro JCT	Leaside TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C16L	1	Cherrywood TS	Sheppard TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C16L	2	Sheppard TS	Leaside TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C17L	1	Cherrywood TS	Scarboro JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS

Operation Designation	Sect.	From	To	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
C17L	2	Bermondsey TS	Leaside TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C17L	3	Scarboro JCT	Bermondsey TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C2L	5	Cherrywood TS	Ellesmere JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C2L	6	Ellesmere JCT	Scarboro JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C2L	7	Scarboro JCT	Leaside TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C3L	4	Leaside Str 4-5 JCT	Leaside TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C3L	5	Cherrywood TS	Ellesmere JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C3L	6	Ellesmere JCT	Scarboro JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C3L	7	Scarboro JCT	Leaside Str 4-5 JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C3L	10	Leaside Str 4-5 JCT	Leaside TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
C7BM	3	Chats Falls SS	Fitzroy JCT	OTHER	LC	Reconfiguration of normal operating system
D1A	8	Fibre JCT	D1A STR 4A JCT	OTHER	LC	Disconnection of Customer
D6V	10	Campbell TS	Speed River JCT	DFL	N	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement

Operation Designation	Sect.	From	To	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
D7V	11	Speed River JCT	Cedar TS	N	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
E1C	1	Ear Falls TS	Selco JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
E1C	2	Selco JCT	Slate Falls JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
E1C	3	Etruscan JCT	Placer JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
E1C	8	Golden Patricia JCT	Etruscan JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
E1C	11	Slate Falls JCT	Golden Patricia JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
E4D	1	Ear Falls TS	Scout Lake JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
E4D	2	Scout Lake JCT	Dryden TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
F11C	2	Speedsville JCT	Preston TS	OTHER	DFL	EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement

Operation Designation	Sect.	From	To	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
F11C	7	Freeport SS	Freeport SS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
F12C	7	Freeport SS	Freeport SS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
H2	1	Wiltshire TS	Wiltshire TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K11W	1	Manby TS	Runnymede TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K11W	2	Toronto Runnymede TS	Toronto Wiltshire TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K12	1	Karn TS	Woodstock TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
K12	2	Woodstock TS	Commerce Way TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
K12W	1	Manby TS	Runnymede TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K12W	2	Toronto Runnymede TS	Toronto Wiltshire TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K1W	1	Manby TS	St.Clair Avenue JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K1W	2	St. Clair Avenue JCT	Toronto Wiltshire TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K24F	1	Kenora TS	Rainy River Gold JCT	DFL	N	Customer Connection: Rainy River Gold CTS

Operation Designation	Sect.	From	To	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
K3W	1	Manby TS	St.Clair Avenue JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K3W	2	St. Clair Avenue JCT	Toronto Wiltshire TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
K7	1	Karn TS	Woodstock TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
K7	2	Woodstock TS	Commerce Way TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
L13W	1	Leaside TS	Balfour JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
L13W	2	Balfour JCT	Bridgman JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
L13W	3	Bridgman JCT	Dufferin JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
L13W	4	Dufferin JCT	Wiltshire TS	DFL	OTHER	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
L13W	7	Bridgman JCT	Bridgman TS	OTHER	LC	Reconfiguration of normal operating system
L14W	1	Leaside TS	Bayview JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
L14W	2	Bayview JCT	Birch JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
L14W	3	Birch JCT	Bridgman JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
L14W	4	Bridgman JCT	Wiltshire TS	DFL	OTHER	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS

Operation Designation	Sect.	From	To	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
L18W	2	Leaside TS	Bayview JCT	DFL	OTHER	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
M20D	16	Preston TS	Preston TS	OTHER	DFL	Database cleanup
M21D	16	Preston TS	Preston TS	OTHER	DFL	Database cleanup
M31W	4	Salford JCT	Ingersoll JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
M31W	6	Ingersoll JCT	Karn TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
M32W	6	Salford JCT	Ingersoll JCT	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
M32W	8	Ingersoll JCT	Karn TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
R13K	1	Richview TS	Manby TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
R13K	2	Manby TS	Manby TS	DFL	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
R1K	1	Richview TS	Manby TS	N	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
S3S	2	Kapuskasing R Jct	Tembec Kapuskas CTS	OTHER	LC	Database cleanup
W3T	1	Buchanan TS	Kettle Creek JCT	OTHER	LC	Reconfiguration of normal operating system
W3T	2	Kettle Creek JCT	St.Thomas TS	OTHER	LC	Reconfiguration of normal operating system
W4T	1	Buchanan TS	Kettle Creek JCT	OTHER	LC	Reconfiguration of normal operating system
W4T	2	Kettle Creek JCT	St.Thomas TS	OTHER	LC	Reconfiguration of normal operating system

Witness: Clement Li, Henry Andre

VECC INTERROGATORY #49

Reference:
I1-02-02

Interrogatory:

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.

Response:

a) A list of new transmission station assets that were not included in EB-2016-0160 is provided in the table below.

Station Number	Station Name	Functional Category (EB-2019-0082)	Explanation
1276	Clarington TS	N	EB-2016-0160 Project D01: Clarington TS
2176	Bellman JCT	N,LC	Database cleanup
7144	Leamington TS	TC	EB-2016-0160 Project D14: Leamington TS

b) A list of the transmission station assets whose functional category has changed from that in EB-2016-0160 is provided in the table below. All changes in Functional Category listed in the table below are a result of the OEB's Decision in proceeding EB-2011-0043, where the definition of Network asset was expanded to include certain assets previously captured under the definition of a Line Connection asset.

Station Number	Station Name	Functional Category (EB-2019-0082)	Functional Category (EB-2016-0160)	Explanation
1051	Manby TS	N,LC,TC	LC,TC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
1104	Leaside TS	N,TC	LC,TC	& Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
1116	Wiltshire TS	N,TC	TC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D19: Runnymede TS
4010	Brant TS	N,TC	TC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS
4013	Burlington TS	N,TC	N,LC,TC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
4043	Guelph North JCT	N,LC	N	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2014-0140 Project D5: Guelph Area Transmission Reinforcement
6192	Ear Falls TS	N,TC	LC,TC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2019-0082 Project SS02: Wataynikaneyap Line to Pickle Lake Connection
7238	Karn TS	N	LC	Application of OEB Decision in Proceeding EB-2011-0043 to the EB-2016-0160 Project D09: Brant TS

VECC INTERROGATORY #50

Reference:
I1-03-01

Interrogatory:
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.

Response:
a) All new Dual Function Lines that were not included in EB-2016-0160 have been identified in Exhibit I, Tab 10, Schedule VECC-48, part (a).

b) As described in Exhibit I1, Tab 1, Schedule 2 of the evidence, the allocation factors used to split the Dual Function Line ("DFL") asset value between Network and Line Connection functions are derived using the average forecast monthly coincident peak demand of customer load connected to the DFL and the minimum of the average of summer and winter transmission capacity of the DFL. Therefore, the allocation might differ from one year to another due to any change in customer load forecast or due to addition of new DFL lines.

Hydro One compared the DFL allocation factors with those provided in EB-2016-0160 and any differences found were not significant and can be explained by the reasons mentioned above; with the exception of two line segments (D6V and D7V).

In preparing response for this interrogatory, an error was identified in calculating the allocation factors for lines D6V and D7V. The table below provides the allocation factors for these lines as filed in EB-2016-1060, in the current application (EB-2019-0082) and the updated values. The updated allocation factors did not impact the combined asset value (for D6V and D7V) allocated to Network and Line Connection rate pools.

Operating Designation	DFL Allocators (EB-2016-0160)		DFL Allocators (EB-2019-0082)		Updated DFL Allocators	
	% Network	% Connection	% Network	% Connection	% Network	% Connection
D6V	76%	24%	57%	43%	67%	33%
D7V	76%	24%	78%	22%	67%	33%

VECC INTERROGATORY #51

Reference:
I1-03-02

Interrogatory:
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.

Response:
a) A list of new Generator Line Connections that were not included in EB-2016-0160 is provided in Table 1 below.

b) As described in Exhibit I1, Tab 1, Schedule 2 of the evidence, the allocation of asset value for Generator Line Connections between "Generators" and "Load" depends on the sum of the maximum annual non-coincident peak demand of all delivery points connected to the connection facility and the maximum installed capacity of generation connected to that facility. Therefore, the allocation might differ from one year to another if there was a change in the annual non-coincident peak demand or due to connection/disconnection of a generator.

Hydro One compared the allocation factors for Generation Line Connections in this application with those provided in EB-2016-0160 and any differences found were not significant and can be explained by the reasons mentioned above.

Table 1 – List of New Generator Line Connections

Operation Designation	Sect	From	To	% Generator	% Load	Explanation
A5RK	8	A5RK STR O7 JCT	Overbrook TS	15%	85%	EB-2016-0160 Project D10: Riverdale Junction to Overbrook TS
B20P	8	Bruce A TS	Bruce HW Plant B TS	100%	0%	Reconfiguration of normal operating system
B22D	12	Armow JCT	Armow CSS	100%	0%	New Generation Connection: Armow GS
B23D	12	Zurich JCT	Zurich CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
B24P	8	Bruce A TS	Bruce HW Plant B TS	100%	0%	Reconfiguration of normal operating system
B4V	10	Southgate JCT	Southgate CGS	100%	0%	New Generation Connection: Southgate CGS
B88H	5	York EnergyCentr JCT	York EnergyCentr CGS	100%	0%	EB-2016-0160 Project D07: York Region
B89H	5	York EnergyCentr JCT	York EnergyCentr CGS	100%	0%	EB-2016-0160 Project D07: York Region
C31	1	Chatham SS	C31 SKWP CMS JCT	100%	0%	Generator was inadvertently omitted in EB-2016-0160
D2H	21	Calder JCT	Calder CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
D2L	19	New Liskeard JCT	New Liskeard JCT #2	100%	0%	Generator was inadvertently omitted in EB-2016-0160
D6T	1	Pinard TS	Pinard JCT #2	69%	31%	New Generation Connection: Peter Sutherland Senior GS
D6T	2	Pinard JCT #2	Abitibi Canyn JCT #2	69%	31%	New Generation Connection: Peter Sutherland Senior GS
D6T	3	Pinard JCT #2	Abitibi Canyn JCT #2	69%	31%	New Generation Connection: Peter Sutherland Senior GS
D6T	4	Abitibi Canyn JCT #2	P Sutherland Sr JCT	69%	31%	New Generation Connection: Peter Sutherland Senior GS
D6T	9	P Sutherland Sr JCT	P Sutherland Sr SYD	100%	0%	New Generation Connection: Peter Sutherland Senior GS
E6L	1	Seaforth TS	Egmondville CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
H	1	Summerhaven SS	Summerhaven CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
H22D	4	Little Long JCT	Little Long 2 JCT	100%	0%	Generator was inadvertently omitted in EB-2016-0160
H9W	1	Beach TS	West Lincoln JCT	100%	0%	New Generation Connection: West Lincoln CGS
H9W	2	West Lincoln JCT	West Lincoln CSS	100%	0%	New Generation Connection: West Lincoln CGS
K25BUS	1	Sandusk SS	Sandusk CGS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
K2M	1	Rabbit Lake SS	Norman JCT	100%	0%	Generator was inadvertently omitted in EB-2016-0160
L20D	5	Smoky Falls JCT	Harmon JCT	100%	0%	Generator was inadvertently omitted in EB-2016-0160
L20D	6	Harmon JCT	Kipling JCT	100%	0%	Generator was inadvertently omitted in EB-2016-0160
L20D	7	Kipling JCT	Kipling 2 GS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
L20D	8	Harmon JCT	Harmon 2 GS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
L29C	5	East Lk StClair JCT	East Lk StClair CGS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
L7S	3	Seaforth L7S JCT	Goshen JCT	51%	49%	Generator was inadvertently omitted in EB-2016-0160

Operation Designation	Sect	From	To	% Generator	% Load	Explanation
L7S	13	Seaforth TS	Seaforth L7S JCT	51%	49%	Generator was inadvertently omitted in EB-2016-0160
L7S	17	Goshen JCT	Goshen CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
N5M	5	Grand JCT	Grand CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
Q21P	1	Beck #2 TS	Beck Pump Storage GS	100%	0%	New Generation Connection: Beck Pump Storage GS
Q22P	1	Beck #2 TS	Beck Pump Storage GS	100%	0%	New Generation Connection: Beck Pump Storage GS
S24V	1	Orangeville TS	Shannon CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
S2B	1	Martindale TS	Copper Cliff JCT	60%	40%	Generator was inadvertently omitted in EB-2016-0160
S2B	2	Copper Cliff JCT	Creighton JCT	60%	40%	Generator was inadvertently omitted in EB-2016-0160
S2B	3	Creighton JCT	Vermillion JCT	60%	40%	Generator was inadvertently omitted in EB-2016-0160
S2B	4	Vermillion JCT	Ethel Lake JCT	60%	40%	Generator was inadvertently omitted in EB-2016-0160
S2B	5	Ethel Lake JCT	Turbine JCT	63%	37%	Generator was inadvertently omitted in EB-2016-0160
S2B	7	Turbine JCT	Eacom Nairn Ctr JCT	63%	37%	Generator was inadvertently omitted in EB-2016-0160
S2B	8	Eacom Nairn Ctr JCT	Espanola JCT	66%	34%	Generator was inadvertently omitted in EB-2016-0160
S2B	9	Espanola JCT	Eddy Tap JCT	66%	34%	Generator was inadvertently omitted in EB-2016-0160
S2B	19	Espanola A JCT	McLeans Mtn JCT	66%	34%	Generator was inadvertently omitted in EB-2016-0160
S2B	35	Eddy Tap JCT	Espanola A JCT	66%	34%	Generator was inadvertently omitted in EB-2016-0160
S2B	41	McLeans Mtn JCT	McLeans Mtn CSS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
S2N	1	Strathroy TS	Sydenham JCT	92%	8%	Generator was inadvertently omitted in EB-2016-0160
S2N	2	Sydenham JCT	Adelaide JCT	92%	8%	Generator was inadvertently omitted in EB-2016-0160
S2N	7	Adelaide JCT	Landon JCT	92%	8%	Generator was inadvertently omitted in EB-2016-0160
S2N	14	Landon JCT	Landon CGS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
S47C	3	Erieau WF JCT	Erieau WF CGS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
T1B	10	Red Rock CGS JCT	Cobden JCT	87%	13%	Reconfiguration of normal operating system
T1B	11	Red Rock CGS JCT	Red Rock CGS	87%	13%	Reconfiguration of normal operating system
W2S	1	Buchanan TS	Sydenham JCT	31%	69%	Generator was inadvertently omitted in EB-2016-0160
W2S	2	Sydenham JCT	Strathroy TS	31%	69%	Generator was inadvertently omitted in EB-2016-0160
W8T	10	Lyons JCT	Lyons JCT	31%	69%	Generator was inadvertently omitted in EB-2016-0160
WT1A	1	Lyons JCT	Silvercreek JCT	31%	69%	Generator was inadvertently omitted in EB-2016-0160
WT1A	3	Silvercreek JCT	Silvercreek CGS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
X3H	4	Kingston Solar JCT	Kingston Solar CGS	100%	0%	Generator was inadvertently omitted in EB-2016-0160
Z1E	11	Windsor Airport JCT	Windsor Airport CGS	100%	0%	New Generation Connection: Windsor Airport CGS

Witness: Clement Li, Henry Andre

VECC INTERROGATORY #52

Reference:

I1-03-03

Interrogatory:

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.

Response:

a) A list of new Generator Station Connections that were not included in EB-2016-0160 is provided in the table below.

Asset Number	Station Name	Functional Category (EB-2019-0082)	% Generator	% Load	Explanation
1044	Creighton JCT	LC	60%	40%	Generator was inadvertently omitted in EB-2016-0160
251	Hamilton Beach TS	LC	32%	68%	New Generation Connection: West Lincoln CGS

b) Please see Hydro One's response to Exhibit I, Tab 10, Schedule VECC-51 part (b).

Witness: Clement Li, Henry Andre

VECC INTERROGATORY #53

Reference:

I2-02-01-01

Interrogatory:

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?

Response:

a) Please refer to Hydro One's response to Exhibit I, Tab 1, Schedule OEB-226, part (b).

b) No. Customers who would be better off with the alternative NSC determinant do not necessarily have their peak outside of the peak period.

c) There were discussions with the IESO regarding implementation issues with changing the Network charge determinant definition, but no discussion regarding the merits of altering the definition of the peak period so as to include hour 20.

VECC INTERROGATORY #54

Reference:
I2-04-01 p. 1-3
EB-2014-0140 Decision
EB-2014-0140, HONI's Tx 2015-2016 Transmission Revenue Requirement Application – Application, Settlement Agreement and Evidence

Interrogatory:

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.

Response:

a) Confirmed. On page 25 of the Settlement Agreement in EB-2014-0140 it states that: "*agreement on the level of ETS rate of $1.85 per MWh shall not be construed as acceptance of the methodology, assumptions, or scenarios used in the Elenchus Study*" and further states that "*because this is the first case where a cost allocation study was filed in evidence to inform the ETS Rate, the parties observe that the cost allocation methodology proposed by the Elenchus Study remains untested and the parties do not necessarily agree with that methodology. The parties therefore 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) Confirmed. In the OEB Decision recorded in the December 2, 2014 transcript of this proceeding, the OEB accepted and approved the Settlement Agreement as filed and did not opine on any matters specifically related to ETS or the Elenchus Study.

VECC INTERROGATORY #55

Reference:

I2-04-01 p. 3-4

Interrogatory:

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.

Response:

a) The export volumes for 2020 to 2022 were calculated based on a three year rolling average of the prior year's amounts. The table below provides the export volumes for 2020 to 2022 period as used in the initial Application:

2015 Actual	2016 Actual	2017 Actual	2018 (2015 - 2017 Avg)	2019 (2016 - 2018 Avg)	2020 (2017- 2019 Avg)	2021 (2018- 2020 Avg)	2022 (2019- 2021 Avg)
23,138,052	22,157,981	19,346,599	21,547,544	21,017,374	20,637,172	21,067,364	20,907,304

b) The same calculation as in part (a) was used for the Updated Application; however the data for 2018 was updated to reflect actual volumes. The table below provides the export volumes for 2020 to 2022 period as used in the Updated Application:

2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 (2016 - 2018 Avg)	2020 (2017- 2019 Avg)	2021 (2018- 2020 Avg)	2022 (2019- 2021 Avg)
23,138,052	22,157,981	19,346,599	18,771,464	20,092,015	19,403,359	19,422,279	19,639,218

VECC INTERROGATORY #X

Reference:

H-01-02-11
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

Interrogatory:

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?

Response:

a) Confirmed.

b) No. As mentioned in Exhibit I, Tab 12, Schedule VECC-28 part (f) subpart (ii) in EB-2016-0160 "*Hydro One's CDM peak savings used in load forecasting is the same as the peak reduction associated with energy saving targets. Considering there is no incremental peak reduction from existing and future demand response resources over the forecast period, Hydro One use the implicit method to incorporate demand* *response impacts in load forecasting*". The demand response resources include: ICI, dispatched load and demand response (auction).

c) Please see response to part (b) above.

d) Please see response to part (b) above.