HYDRO ONE
TRANSMISSION
EB-2019-0082

VECC COMPENDIUM Panel 4

November 1, 2019

TAB 1

The following subsections describe how the functionalization of transmission assets, as described in Section 3, is used as a basis to allocate Hydro One's transmission revenue requirement components into functional categories.

4.1 ALLOCATION OF ASSET VALUE

As a starting point, it is necessary to allocate the Gross Book Value ("GBV") of transmission assets to functional categories. Assignment of the physical assets to the functional categories and the subsequent split of the Dual Function Lines and Generation Connection assets, as described above, yields the functionalization of the GBV of transmission assets into the functional categories shown below:

- Network
- Network Portion of Dual Function Line
- Line Connection
- Line Connection Portion of Dual Function Line
- Transformation Connection
- Generator Line Connection
- Generator Transformation Connection (includes Generation Station Switchyards)
- Common
- Other

Once the GBV has been allocated to the functional categories, the Net Book Value ("NBV") of transmission assets is determined by assigning the accumulated depreciation, discussed in Exhibit C, Tab 1, Schedule 1, to the functional categories listed above in proportion to the share of GBV of assets in each functional category by Uniform System of Accounts ("USofA"). A summary of the GBV and NBV of assets by functional category is provided in Exhibit I1, Tab 4, Schedule 1.

TAB 2

DETAILED REVENUE REQUIREMENT BY RATE POOL

Table 1: 2020 Detailed Revenue Requirement by Rate Pool

	Rate Pool Revenue Requirement ($ Millions)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
OM&A	181.7	37.8	88.2	307.7
Taxes other than Income Taxes	42.7	7.9	17.6	68.1
Depreciation of Fixed Assets	254.5	42.1	124.3	421.0
Capitalized Depreciation	(8.3)	(1.5)	(3.5)	(13.3)
Asset Removal Costs	33.8	6.2	14.2	54.1
Other Amortization	8.0	1.5	3.3	12.8
Return on Debt	207.0	38.3	85.3	330.6
Return on Equity	278.3	51.5	114.7	444.5
Income Taxes	30.3	5.6	12.5	48.3
Total Revenue Requirement	**1,028.0**	**189.3**	**456.5**	**1,673.8**
External Revenues	(19.3)	(3.5)	(8.6)	(31.4)
WMS Revenue	0.0	0.0	(0.1)	(0.1)
Regulatory Assets	3.2	0.6	1.4	5.2
Export Revenue Variance	1.6	0.0	0.0	1.6
Export Revenue	(35.9)	0.0	0.0	(35.9)
LVSG Credit	0.0	0.0	14.8	14.8
Total Rates Revenue Requirement	**977.6**	**186.3**	**464.1**	**1,628.0**

The detailed revenue requirement by rate pool for the years 2021 and 2022 are provided below in Table 3 and Table 4, respectively. The 2021 and 2022 rates revenue requirement has been allocated among the proposed rate pools using the methodology approved by the OEB in its Decision and Order, dated April 25, 2019, for Hydro One's 2019 Transmission Revenue Requirement in Proceeding EB-2018-0130. The methodology uses the proposed 2020 total revenue requirement as shown in Table 1 to determine the percentage split by rate pool as presented in Table 2.

Table 2: Percentage Split of Total Revenue Requirement by Transmission Rate Pool

	Network	**Line Connection**	**Transformation Connection**	**Total**
2020 Proposed Total Revenue Requirement	1,028.0	189.3	456.5	1,673.8
Percentage Split by Rate Pool	61%	11%	27%	100%

This percentage allocation is used to allocate the 2021 and 2022 total revenue requirement among the three transmission rate pools The rates revenue requirement offsets are then applied to the total revenue requirement to derive the total rates revenue requirement. The External Revenues and Regulatory Assets Balance are allocated based on the total revenue requirement spilt by rate pools; whereas Export Revenues are 100% allocated to the Network rate pool and WMS and LVSG revenues are 100% allocated to the Transformation Connection rate pool.

Table 3: 2021 Detailed Revenue Requirement by Rate Pool

	Rate Pool Revenue Requirement ($ Millions)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
Percentage Split by Rate Pool	*61%*	*11%*	*27%*	*100%*
Total Revenue Requirement	**1,084.4**	**199.7**	**481.6**	**1,765.8**
External Revenue	(20.1)	(3.7)	(8.9)	(32.7)
WMS Revenue	0.0	0.0	(0.1)	(0.1)
Export Revenue	(35.9)	0.0	0.0	(35.9)
Regulatory Assets	3.2	0.6	1.4	5.2
Export Revenue Variance	1.6	0.0	0.0	1.6
LVSG Credit	0.0	0.0	15.6	15.6
Total Rates Revenue Requirement	**1,033.2**	**196.6**	**489.6**	**1,719.4**

TAB 3

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).

TAB 4

FEES FOR WHOLESALE METER SERVICE

1. INTRODUCTION

This Exhibit summarizes Hydro One's proposal for the derivation of the proposed Wholesale Meter Service ("WMS") fee that will recover the revenue requirement associated with Meter Service Provider ("MSP") services to wholesale revenue metering ("WRM") assets.

2. COSTS ASSOCIATED WITH WHOLESALE REVENUE METERING ASSETS

The WRM installations are comprised of such assets as: recorders, physical meters and related instrument transformers, wiring, and panels that require ongoing operations and maintenance expenses, including costs associated with activities to comply with the Market Rules administered by the Independent Electricity System Operator ("IESO"), and asset related charges such as depreciation and a share of the other revenue requirement costs (e.g., return on capital, taxes, etc.).

For every metering installation with respect to which a Metered Market Participant ("MMP") arranges to exit the transitional arrangement, Hydro One Transmission shall cease to be responsible for these direct or indirect costs that are required to maintain, repair, or replace any equipment necessary for wholesale revenue metering or any other purpose related to the metering installation.

Since market opening in 2002, MMPs have been making arrangements to exit the transitional arrangement upon seal expiry of their WRM installations, as per the Market Rules, reducing Hydro One Transmission's ownership of WRMs.

TAB 5

UNDERTAKING - JT 2.34 - Q9

Reference:

Exhibit I/Tab 01/Schedule 149 b) (OEB Staff-149 b))
Exhibit I/Tab 10/Schedule 16 (VECC-16)

Undertaking:

a) Please provide the actual MSP Revenues for each of the years 2016, 2017 and 2018.

b) Please provide the actual Low Voltage Switch Gear provided for each of the years 2016, 2017 and 2018.

Response:

a) The actual MSP Revenues in 2016, 2017 and 2018 are $0.6 million, $0.4 million and $0.5 million, respectively.

b) The actual Low Voltage Switch Gear provided in 2016, 2017 and 2018 are $13.0 million, $13.4 million and $14.1 million, respectively.

TAB 6

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.

Table 2: Load Impact of CDM on Ontario Demand (MW)

Year	Cumulative CDM Impact on Peak Demand *	Cumulative CDM Impact on 12-month Average Peak Demand **
2006	289	211
2007	778	568
2008	893	652
2009	997	729
2010	1,167	852
2011	1,318	963
2012	1,470	1,074
2013	1,621	1,184
2014	1,820	1,319
2015	1,942	1,434
2016	2,167	1,638
2017	2,099	1,638
2018	2,391	1,924
2019	2,799	2,252
2020	3,197	2,552
2021	3,341	2,654
2022	3,509	2,775

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

** The figures represent the load impact of CDM on monthly peaks, averaged over 12 months in the year.

3.7 EMBEDDED GENERATION FORECAST

In relation to Ontario demand, a total of 568 MW of embedded generation was assumed to be in place in 2017. An additional 10 MW in 2018, 24 MW in 2019, 101 MW in 2020, and an average of 8 MW per year over the years 2021 to 2022 of new embedded generation is assumed in the load forecast. The figures represent 12-month average peak and are based on information provided by IESO, which reflects renewable energy projects initiated by the IESO (and previously the OPA).

4. LOAD FORECASTING METHODOLOGY

Hydro One Transmission's system load forecast is developed using both econometric and end-use approaches. The forecast base year is corrected for abnormal weather conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized base year value. The load impacts of CDM and embedded generation are added back to the historical values during the modeling process (see Figure 2 and Section 4.2).

TAB 7

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

TAB 8

BUSINESS LOAD FORECAST AND METHODOLOGY

1. INTRODUCTION

This Exhibit discusses the Hydro One Transmission system load forecast and the related methodology. The key load forecast supporting Hydro One's transmission rate case is the hourly demand load forecast by customer delivery point. This forecast is used to prepare the charge determinant forecast for the following rate categories: Network Pool, Line Connection Pool, and Transformation Connection Pool. The load forecast in support of this Application was prepared in December 2018, using the available economic and forecast information.

Hydro One Transmission's forecast of average 12-month peak load for 2020 to 2022 for Ontario as a whole and for its three rate categories are shown in Table 1. The impacts of Conservation and Demand Management ("CDM") and embedded generation are included.

Table 1: Hydro One's 2020-2022 Load Forecast
(12-Month Average Peak in MW)

		Hydro One Rate Categories (Charge Determinants)		
	Ontario Demand	Network Connection	Line Connection	Transformation Connection
2020	19,586	19,604	19,071	16,252
2021	19,451	19,469	18,941	16,142
2022	19,304	19,322	18,800	16,021

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, as detailed in Section 3.6 below.

TAB 9

UNDERTAKING - JT 2.34 - Q3

Reference:

Exhibit I/Tab 10/Schedule 24 b); d) and h) i)
(VECC-24 b); d) & h) i))
Exhibit E/Tab 3/Schedule 1, Table 3

Undertaking:

Preamble: The response to VECC 24 b) contains the following data with respect to energy savings from CDM:

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

Reference 6 from VECC 24 d) contains the following data with respect to historic energy savings from CDM which differs from that in VECC 24 b) in 2015 and after:

Conservation Achievements												
TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2	5.2	6.3
Conservation Program	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	9.7	9.4	10.0

Finally Reference 7 from VECC 24 d) contains historic data with respect to net energy savings from EE programs.

a) Please confirm that the 2006-2017 energy savings reported in References 6 and 7 of VECC 24 d) are not the same and that both differ from the savings reported in the 2013 LTEP for the same period.

b) Which of the references in VECC 24 d) (#6 or #7) contain the most recently issued values from the IESO regarding historic 2006-2017 CDM energy savings?

c) Which historical series of energy savings did HON use for purposes of developing its forecasting models?

Witness: Clement Li, Bijan Alagheband

d) If the most recent data from the IESO (per part (b)) was not used please explain why.

e) If the most recent data from the IESO regarding the historic and forecast energy savings differs from that in the 2013 LTEP, please explain how the demand savings history/forecast from the 2013 LTEP can still be valid – as claimed in the response to VECC 24 h) i).

f) The materials provided by the IESO for the Technical Planning Conference in September 2018 included the following forecast for new Conservation Program Savings in 2018 and after (VECC 24 d), Reference 6, Slide 20):

Long Term Conservation Forecast					
	2018	2019	2020	2021	2022
New Conservation Program Savings (TWh)	1.99	3.37	4.50	4.90	5.30
New Conservation Program Savings (MW)	317	537	710	773	831

Is the CDM forecast in Exhibit E/Tab 3/Schedule 1, Table 3 consistent with this forecast?

<u>Response:</u>

a) Confirmed.

b) The information in reference #6 was released in October 2018 and the information in #7 was shared by the IESO with Hydro One in January 2019.

c) The energy savings in the 2016 OPO was used for the purpose of developing the load forecast.

d) Hydro one has considered all the available CDM information to be assured that the assumptions used for the load forecast are reasonable. The comparison of the energy savings in the 2016 OPO and 2018 Technical conference is as follows:

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2016 OPO	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	12.8	14.3	15.9
IESO's Technical Planning Conference in September 2018	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	13.9	14.6	16.3

UNDERTAKING - JT 2.34 - Q4

Reference:

Exhibit I/Tab 10/Schedule 26 a) & b)
(VECC-26 a) & b)) & Exhibit I/Tab 10/Schedule 27 a)
(VECC-27 a))

Undertaking:

a) VECC 27 a) indicates that none of the forecast models used provide a forecast of the 12 monthly peaks. Rather, the monthly peaks are forecast by applying the growth rates from the models to a base year's peak values. However, VECC 26 indicates that the actual 2018 monthly peak values were not known when the forecast was determined (part a)) but also indicates that the growth rates were applied to forecast values for the 2018 billing determinants. How were these forecast 2018 billing determinants established (given the models do not forecast monthly peaks)?

Response:

a) The forecast values of the 2018 billing determinants were established by applying the forecast growth rates for 2018 to the 12-month average value of billing determinants in the year 2017.

TAB 10

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.

TAB 11

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?

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.

TAB 12

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.

TAB 13

connect the transmission delivery point to a network station. Similarly, customers will not incur Line Connection service charges for demand at a transmission delivery point located at a network station.

The billing demand for the Line Connection service charge is the loss-adjusted demand supplied to the delivery point from the transmission system. Furthermore, the demand that is supplied by a generator unit or energy storage facility, through a transmission delivery point that attracts Line Connection service charges, is added to the billing demand if the required government approvals for the generator unit or energy storage facility is obtained after October 30, 1998 and if the generator unit nameplate rating is 2MW or more for renewable generation and 1MW or higher for non-renewable generation or if the individual inverter unit capacity is 1MW or higher for energy storage or solar generators. These charges also apply to the incremental capacity amount associated with any refurbishments or expansions to a generator or generation facility approved after October 30, 1998, for which the incremental generator nameplate capacity is 2MW or more for renewable generation and 1MW or higher for non-renewable generation of the approved refurbishment or if the individual inverter unit capacity is 1MW or higher for expansion of energy storage facilities or solar generators.

The 2020 to 2022 hourly load forecast data for each transmission delivery point, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Line Connection service charges as shown in Table 1.

4.2 TRANSFORMATION CONNECTION

The Transformation Connection service charge determinant is the customer’s non-coincident monthly peak demand, as detailed in the proposed Ontario Uniform Transmission Rate Schedules provided in Exhibit I2, Tab 6, Schedule 2, Attachment 1.

TAB 14

Exhibit I, Tab 3, Schedule 1 (APPRO 1) – Extract from Attachment 1

Demand Data Tab

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	
NCP TEST RESULTS	

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Domestic	2 Export
Volume				
MWh	MWh	154,304,388	135,504,388	18,800,000
Peak MWh	PMWh	-		
CO-INCIDENT PEAK				
1 CP	CP1	-		
4 CP	CP4	-		
12 CP	CP12	266,872	241,536	25,336
High 5	High5	-	-	-

(dark grey)	Values are not used
(light)	Values Used

JT 1.36 – Q1 c) – Extract from Attachment 1

Demand Data Tab

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	
NCP TEST RESULTS	

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Domestic	2 Export
Volume				
MWh	MWh	154,907,747	135,504,388	19,403,359
Peak MWh	PMWh	-		
CO-INCIDENT PEAK				
1 CP	CP1	-		
4 CP	CP4	-		
12 CP	CP12	266,872	241,536	25,336
High 5	High5	-	-	-

(dark grey)	Values are not used
(light)	Values Used