EB-2019-0018

HYDRO ONE TRANSMISSION EB-2019-0082

VECC COMPENDIUM Panel 2

October 25, 2019

TAB 1

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Susan Frank
Vice President and Chief Regulatory Officer
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BY COURIER

November 6, 2012

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2012-0031 – Hydro One Networks' 2013 and 2014 Transmission Revenue Requirement Application – Hydro One Update to Settlement Agreement

Further to Ms. Varjacic's letter of November 2, 2012, attached please find the updated Settlement Agreement which provides more detailed evidentiary references.

An electronic copy of the Agreement have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

I-2-10.03 CCC 3	CCC Interrogatory #3
I-2-10.04 CCC 4	CCC Interrogatory #4
I-2-10.05 CCC 5	CCC Interrogatory #5
I-2-14.01 CME 1	CME Interrogatory #1
JT1.1 TCR Staff 4	OEB Technical Conference Response #4
KT1.12	Undertaking Response #12

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

LOAD FORECAST AND REVENUE FORECAST

3. Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

   Settled. For the purposes of reaching a settlement, all parties accept Hydro One's load forecast as set out in Exhibit A, Tab 15, Schedule 2. Hydro One continues to apply the same forecasting methodology previously approved by the Board in EB-2010-0002 which the parties agree remains appropriate.

   The impacts of CDM and Demand Response and how they are reflected in the load forecast were the primary areas of concern for some intervenors. The Board had some concern in this area as well in prior proceedings. In EB-2010-0002, Hydro One's last Transmission Rates Application, the Board directed Hydro One to work with the OPA to devise a means of effectively and accurately measuring CDM impacts. Hydro One has done so and has relied upon the latest CDM and Demand Response forecasts in its load forecast for the test years.

   There remains some concern on the part of certain intervenors about the accuracy and reliability of the CDM and Demand Response forecasts prepared by the OPA. In order to address those concerns, Hydro One has agreed to establish a new variance account to track the impact of actual CDM and Demand Response results on the Load Forecast and the resulting impact on revenue requirement.

   Hydro One agrees to set up a variance account to track the difference between the forecast of 755MW for 2013 and 1158MWfor 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs. Hydro One will use the annual results reported by the OPA in September of each year for the verified results of the previous year in accordance with the CDM Guidelines issued by the Board in EB-2012-0003. Time-of-use savings will not be included in this variance account because they are currently not included in the annual province-wide CDM program results reported by the OPA.

Hydro One also agreed to track the actual Demand Response results against the forecast as set out in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix A, Table 8 of 836MW in 2013 and 880MW2014 (net of 317MW and 410MW respectfully for 2013 and 2014 already included in CDM program results delivered by LDCs) in this variance account. Hydro One will use annual Demand Response results provided by the OPA each September for results of the previous year in a similar format as the province-wide CDM results delivered by the LDCs.

The disposition of the balance in the LDC CDM and Demand Response Variance Account will be part of a future Rate Application.

Evidence: The evidence in relation to this issue includes the following:

A-6-1	Compliance with OEB Filing Requirements for Electricity Transmitters
A-15-1	Economic Indicators
A-15-2	Business Load Forecast and Methodology
A-15-2 Appendix A	Monthly Econometric Model
A-15-2 Appendix B	Annual Econometric Model
A-15-2 Appendix C	End-Use Model
A-15-2 Appendix D	Historical Ontario Demand and Charge Determinant Data
A-15-2 Appendix E	Consensus Forecast for Ontario GDP and Housing Starts
A-15-2 Appendix F	Forecast Accuracy
A-15-2 Attachment 1	Incorporating Conservation and Demand Management Impacts in the Load Forecast
I-3-1.01 Staff 16	OEB Interrogatory #16
I-3-1.02 Staff 17	OEB Interrogatory #17
I-3-1.03 Staff 18	OEB Interrogatory #18
I-3-1.04 Staff 19	OEB Interrogatory #19
I-3-1.05 Staff 20	OEB Interrogatory #20
I-3-1.06 Staff 21	OEB Interrogatory #21
I-3-1.07 Staff 22	OEB Interrogatory #22
I-3-2.01 LPMA 2	LPMA Interrogatory #2
I-3-2.02 LPMA 3	LPMA Interrogatory #3
I-3-2.03 LPMA 4	LPMA Interrogatory #4
I-3-2.04 LPMA 5	LPMA Interrogatory #5
I-3-3.01 EP 8	Energy Probe Interrogatory #8
I-3-3.02 EP 9	Energy Probe Interrogatory #9
I-3-3.03 EP 10	Energy Probe Interrogatory #10
I-3-5.01 VECC 15	VECC Interrogatory #15
I-3-5.02 VECC 16	VECC Interrogatory #16
I-3-5.03 VECC 17	VECC Interrogatory #17
I-3-5.04 VECC 18	VECC Interrogatory #18
I-3-5.05 VECC 19	VECC Interrogatory #19

TAB 2

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2016-0160

HYDRO ONE NETWORKS INC.

Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018

BEFORE: Ken Quesnelle
Vice Chair and Presiding Member

Emad Elsayed
Member

Peter C. P. Thompson, Q.C.
Member

September 28, 2017

Revised: October 11, 2017

One says will have a negligible effect on the $54 million balance in the account. VECC has not provided any information to establish the amount of the adjustment that it is proposing. In these circumstances, the OEB will not require Hydro One to make such a negligible adjustment.

The second item of relief that VECC seeks is to have the OEB direct Hydro One to include in the account, interest calculated from a date that precedes the earliest date that information is available to determine the amounts to be recorded.

The OEB will not require interest to be paid on amounts from a date earlier than the date on which the principal amount to be recorded in the account can first be determined. Ratepayers would not be in a position to make a demand for any amount owing before the information needed to quantify that amount was available. Before that information is available no quantifiable account payable exists.

Interest normally runs from the date that a quantifiable demand can be made. The OEB finds VECC's proposed interest calculation commencement date to be incompatible with this normal commercial practice.[109]

The OEB finds the amount recorded in this account by Hydro One to be appropriate.

Closure or Continuance of the LDC CDM and DR Variance Account for 2017 and 2018

The OEB finds that this account should not be closed at this time as proposed by Hydro One. The account was forecasted to generate a significant credit for ratepayers to the end of 2016 and these variances should continue to be recorded by Hydro One for the next two years. The OEB realizes that the IESO will no longer be providing actual peak savings information in those years. However, this fact should not automatically lead to the closure of the variance account. The OEB directs Hydro One to use its best efforts to obtain from other sources the peak savings information that it needs to determine the variances to be recorded in this account.

Continuance of Other Existing Accounts

The OEB approves the continuance in 2017 and 2018 of the other existing deferral accounts that Hydro One seeks to have continued subject to a requirement that the wording for the 2017 and 2018 In-Service Capital Additions Variance Account will be varied to address the legitimate concerns raised by LPMA.

[109] The OEB notes that the accounting order for this deferral account calls for interest on the deferral account to be recorded on the opening monthly balance in the account. This language effectively recognizes that no interest is to be recorded before the information is available to quantify the amount payable.

TAB 3

CALCULATION OF THE 2017 CDM AND DEMAND RESPONSE (DR) VARIANCE ACCOUNT

1. OVERVIEW

An LDC CDM and DR Variance Account for Transmission was established as part of the Settlement Agreement approved by the OEB in Hydro One's EB-2012-0031 Transmission Application. As part of the Settlement Agreement, Hydro One agreed to track the difference between the forecasted and actual CDM and DR savings in 2013 and 2014.

In Hydro One's EB-2016-0160 Transmission Application, the OEB determined that this account should not be closed and the variances should continue to be recorded by Hydro One for 2017 and 2018. The OEB also recognized that that the IESO no longer provided actual peak savings information, and directed Hydro One to use its best efforts to obtain from other sources the peak savings information needed to determine the variances to be recorded in this account.

2. 2017 FORECASTED CDM PEAK SAVINGS

The CDM peak savings assumptions in HONI's load forecast 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. The forecasted savings due to EE and C&S programs was based on the 2016 IESO Ontario Planning Outlook (OPO) which includes savings due to the historical programs (2006-2014) and the conservation first framework (2015-2020).

Hydro One's 2017 load forecast approved by the OEB included the same total CDM peak savings amount assumed for 2016, as shown in Table 1.[1] As such, the 2017 target peak savings to be used for calculating the CDM and DR Variance Account balance is zero incremental EE and DR peak savings amounts in 2017 over 2016.

Table 1: 2015-2017 CDM peak saving assumptions in the approved 2017 load forecast

	2015	2016	2017
CDM peak impact (MW)	1,434	1,638	1,638

3. CALCULATION OF 2017 ACTUAL PEAK SAVINGS

EE Amounts

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. The difference between the incremental change in actual EE monthly peak savings and the incremental change in monthly peak amounts assumed in the approved forecast was used to calculate the revenue impact tracked in the CDM and DR Variance Account.

ICI Amounts

Hydro One has calculated the ICI peak impacts using a methodology similar to that used by the IESO:

- Compared ICI participant consumption against a baseline consumption value.
- Determined the baseline consumption by taking the hourly average for the previous 90 days excluding weekends, holidays and other ICI days.

[1] Exhibit E1, Tab 3, Schedule 1, pg.20 from EB-2016-0160.

- Used the 30 top peak demand days to capture the impact of customer actions related to the ICI program in recognition of the fact that Class A customers will take actions to reduce their demand on all potential peak days when the temperature is extremely high or low, and not just on the high-five peak days associated with the calculation of Global Adjustment costs.
- Class A customers include both transmission- connected and distribution-connected customers. Given that Hydro One only has meter data to estimate the ICI peak savings for its own distribution Class A participants, the calculation used Hydro One's 17.5% share of all distribution Class A participants in Ontario to estimate the total ICI peak savings from all distribution Class A customers.

The hourly peak data for transmission-connected and distribution-connected ICI participants required to determine the ICI peak impacts was collected from Hydro One's Itron Enterprise Edition (IEE) meter data management system.

The difference in ICI peak impacts observed in 2017 versus 2016 was used to calculate the revenue impact tracked in the CDM and DR Variance Account.

Dispatched Load and DR Auction Amounts

The information on Dispatched Load, as well as the DR auction activation date and capacity impacts, for 2016 and 2017 was provided by the IESO. The difference between 2016 and 2017 is used to calculate the revenue impact tracked in the CDM and DR Variance Account.

Determination of the DR Peak Impacts (MW)

Table 2 shows the monthly actual peak savings for the DR programs in 2016 and 2017, and the calculation of the incremental peak savings achieved in 2017.

Table 2: Actual Peak Savings Achieved (MW)

Month	2016 MW				2017 MW				Incremental MW (2017 vs 2016)				
	ICI	Dispatched load	DR	EE	ICI	Dispatched load	DR	EE	ICI	Dispatched load	DR	EE	Total
Jan	-	11		333	389	55	0	455	389	44	0	122	556
Feb	-	50		329	252	40	0	450	252	(10)	0	121	363
Mar	-	42		305	-	60	0	417	-	18	0	112	130
Apr	-	54		312	-	40	0	422	-	(14)	0	111	97
May	-	94		329	-	40	0	446	-	(54)	0	117	63
Jun	788	55		435	539	117	0	590	(249)	62	0	155	(32)
Jul	915	50		473	1,283	58	0	621	368	8	0	148	524
Aug	926	90	316	431	847	66	0	585	(80)	(24)	-316	154	(266)
Sep	735	94		390	1,495	105	240	530	761	11	240	139	1,151
Oct	-	40		308	-	83	0	419	-	42	0	111	153
Nov	-	40		314	-	40	0	428	-	-	0	114	114
Dec	-	72		334	634	123	0	456	634	51	0	122	807
Total MW	**3,364**	**692**	**316**	**4,294**	**5,440**	**826**	**240**	**5,819**	**2,076**	**134**	**-76**	**1,525**	**3,659**

4. Calculation of Variance Account Amount

Given the forecasted 2017 incremental peak savings is zero, as discussed in Section 2, the 2017 incremental peaks savings to be used for determining the CDM and DR variance account balance are the values shown in Table 2.

The variance account balance is determined by multiplying the amounts in Table 2 by the approved Uniform Transmission Rates ($/kW) and revenue allocation factors in effect over that period, which are shown in Table 3.

Table 3: Uniform Transmission Rates and revenue allocation factors

Period	Uniform Transmission Rates ($/kW)			Hydro One's Revenue Allocator		
	Network	Line Connection	Transformation Connection	Network	Line Connection	Transformation Connection
Jan to Oct 2017	3.66	0.87	2.02	0.93219	0.96648	0.96648
Nov to Dec 2017	3.52	0.88	2.13	0.92828	0.96539	0.96539

The resulting 2017 total dollar variance by transmission rate pool is summarized in Table 4.

Table 4: Total Variance for 2017 EE & DR Savings by Rate Pool ($ Millions)

	ICI	Dispatched load	DR Auction	EE	Total
Network Variance	$ 6.99	$ 0.45	$ (0.26)	5.17	$ 12.35
Line Connection Variance	$ 1.75	$ 0.11	$ (0.06)	1.28	$ 3.08
Transformation Connection Variance	$ 4.12	$ 0.27	$ (0.15)	3.00	$ 7.24
Total Variance $	**$ 12.86**	**$ 0.83**	**$ (0.47)**	**9.46**	**$ 22.67**

TAB 4

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

I-10-VECC-45 a(iii)

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

TAB 5

UNDERTAKING - JT 2.34 - Q2

Reference:

Exhibit I/Tab 10/Schedule 24 d), Attachment 1
(VECC-24 d)-Attachment 1)
Exhibit E/Tab 3/Schedule 1, Tables 2 and 3

Undertaking:

a) Columns BQ, BR and BS of the Excel file report Net Energy Savings for 2015-2017. Similarly, Columns FG, FH and FI of the Excel file report the Net Demand savings for 2015-2017. However, in both instances, all of the values are not numerical (e.g. cell FI749) and totals by category (e.g., ICI) or for the columns overall cannot be calculated. Please provide a revised file containing the numerical values for the net energy and net demand savings for each program and the totals for these years.

b) Based on the Excel file showing IESO reported savings for 2006 to 2014 (i.e., VECC 24 d) - Attachment 1), please provide a schedule that sets out the actual net demand savings in 2014 through 2017 broken down into the following categories: DR, ICI, Dispatched Load and EE.

c) Do the 2017 CDM savings in Exhibit E/Tab 3/Schedule 1, Table 3 match the Net Demand savings attributable to EE programs for the 2017 as reported in Attachment 1 of VECC 24 d)? If not, please explain why.

Response:

a) The revised file containing the numerical values is provided in the attachment.

b) The data reported by the IESO in VECC 24 d) Attachment 1 does not provide the savings in the four categories referenced. The categories in the table provided by the IESO, and the net peak saving (MW) at the end use level are provided below:

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
EE	270	709	796	868	1,009	1,188	1,220	1,387	1,574	1,818	1,807	1,766
C&S	-	17	37	62	100	265	273	308	498	609	706	831
DR	298	662	632	598	509	509	845	1,371	1,483	1,746	2,018	2,116
CBG (customer based gene	-	2	11	11	11	11	11	11	11	11	11	11
Total	568	1,390	1,477	1,540	1,629	1,974	2,350	3,078	3,567	4,185	4,542	4,726

c) No, the values shown in VECC 24 d) Attachment 1 are annual peak values at the end-use level, while the values in Table 3 are 12-month average amounts at the generator level. The values shown in VECC 24d) Attachment 1 were only used for the variance account calculations. For the purpose of load forecasting (i.e., Table 3 values) Hydro One uses total forecast EE and C&S CDM peak savings per the 2013 LTEP in order to have a consistent data set across historical and forecast years, consistent with the load forecasting methodology previously approved by the OEB for Hydro One.

TAB 6

Exhibit JT 2.34 Q2 – Attachment 1 extract

Savings Persistence (kWh & kW)

#	Framework	Program	Description	Source	Res/ Bus/ Other	Dx/ Tx/ Gen	EE/ DR/ CBG	Reporting Year	Implementation Year	2015	2016	2017
489	2010 - 2015	Industrial Transmission Connected Energy Efficiency Program	IAP 1.0	IESO CCR	Bus	Tx	EE	2013	2013	648	648	648
491	2010 - 2015	Industrial Transmission Connected Energy Efficiency Program	IAP 1.0	IESO CCR	Bus	Tx	EE	2014	2014	1,460	1,460	1,460
492	2010 - 2015	Industrial Transmission Connected Energy Efficiency Program	IAP 1.0	IESO CCR	Bus	Tx	EE	2015	2015	5	5	5
493	2010 - 2015	Industrial Transmission Connected Energy Efficiency Program	ECO Table Al	IESO CCR	Bus	Tx	EE	2016	2010	470		
494	2010 - 2015	Industrial Transmission Connected Energy Efficiency Program	ECO Table Al	IESO CCR	Bus	Tx	EE	2016	2011	433		
495	2010 - 2015	Industrial Transmission Connected Energy Efficiency Program	ECO Table Al	IESO CCR	Bus	Tx	EE	2016	2012	4,909		
496	2010 - 2015	Industrial Transmission Connected Energy Efficiency Program	ECO Table Al	IESO CCR	Bus	Tx	EE	2016	2013	-		
497	2015 - 2020	Industrial Accelerator Program 2.0	IAP 2.0	IESO CCR	Bus	Tx	EE	2015	2015	5,469	5,417	5,417
498	2015 - 2020	Industrial Accelerator Program 2.0	IAP 2.0	IESO CCR	Bus	Tx	EE	2016	2015	633	633	633
499	2015 - 2020	Industrial Accelerator Program 2.0	IAP 2.0	IESO CCR	Bus	Tx	EE	2016	2016	-	79,924	79,924
500	2015 - 2020	Industrial Accelerator Program 2.0	IAP 2.0	IESO CCR	Bus	Tx	EE	2017	2015	760	760	760
501	2015 - 2020	Industrial Accelerator Program 2.0	IAP 2.0	IESO CCR	Bus	Tx	EE	2017	2016	-	1,098	1,098
502	2015 - 2020	Industrial Accelerator Program 2.0	IAP 2.0	IESO CCR	Bus	Tx	EE	2017	2017	-	-	11,554
508	Other Influe	Other - DSM Program		Other	Other	Dx	EE	2006	2006	251,647		
511	Other Influe	Other - DSM Program		Other	Other	Dx	EE	2007	2007	236,569	236,569	
512	Other Influe	Other - DSM Program		Other	Other	Dx	EE	2008	2008	13,905	13,205	12,486
513	Other Influe	Other - DSM Program		Other	Other	Dx	EE	2009	2009	18,249	17,752	17,331
514	Other Influe	Other - DSM Program		Other	Other	Dx	EE	2010	2010	15,689	15,269	15,262
515	Other Influe	Enbridge Gas Distribution - Gas DSM Program		Other	Other	Dx	EE	2011	2011	15,690	15,408	15,269
516	Other Influe	Enbridge Gas Distribution - Gas DSM Program		Other	Other	Dx	EE	2012	2012	11,891	11,730	11,677
517	Other Influe	Enbridge Gas Distribution - Gas DSM Program		Other	Other	Dx	EE	2013	2013	6,039	5,980	5,957
518	Other Influe	Enbridge Gas Distribution - Gas DSM Program		Other	Other	Dx	EE	2014	2014	7,060	7,013	6,991
519	Other Influe	Enbridge Gas Distribution - Gas DSM Program		Other	Other	Dx	EE	2015	2015	5,198	5,175	5,163
520	Other Influe	Enbridge Gas Distribution - Gas DSM Program		Other	Other	Dx	EE	2016	2016		4,158	4,140
521	Other Influe	Enbridge Gas Distribution - Gas DSM Program		Other	Other	Dx	EE	2017	2017			3,326
522	Other Influe	Union Gas Limited - Gas DSM Program		Other	Other	Dx	EE	2011	2011	9,851	9,674	9,587
523	Other Influe	Union Gas Limited - Gas DSM Program		Other	Other	Dx	EE	2012	2012	3,704	3,654	3,638
524	Other Influe	Union Gas Limited - Gas DSM Program		Other	Other	Dx	EE	2013	2013	2,727	2,700	2,690
525	Other Influe	Union Gas Limited - Gas DSM Program		Other	Other	Dx	EE	2014	2014	4,612	4,581	4,567
526	Other Influe	Union Gas Limited - Gas DSM Program		Other	Other	Dx	EE	2015	2015	4,612	4,592	4,581
527	Other Influe	Union Gas Limited - Gas DSM Program		Other	Other	Dx	EE	2016	2016		3,690	3,674
528	Other Influe	Union Gas Limited - Gas DSM Program		Other	Other	Dx	EE	2017	2017			2,952
529	Other Influe	Natural Resources Canada - DSM Program		Other	Other	Dx	EE	2011	2011	15,713	15,431	15,292
530	Other Influe	Natural Resources Canada - DSM Program		Other	Other	Dx	EE	2012	2012	29,923	29,518	29,386
531	Other Influe	Natural Resources Canada - DSM Program		Other	Other	Dx	EE	2013	2013	24,936	24,692	24,598
532	Other Influe	Natural Resources Canada - DSM Program		Other	Other	Dx	EE	2014	2014	25,537	25,367	25,287
533	Other Influe	Natural Resources Canada - DSM Program		Other	Other	Dx	EE	2015	2015	23,434	23,334	23,278
534	Other Influe	Natural Resources Canada - DSM Program		Other	Other	Dx	EE	2016	2016		11,717	11,667
535	Other Influe	Natural Resources Canada - DSM Program		Other	Other	Dx	EE	2017	2017			5,859
Total										**4,185,400**	**4,542,126**	**4,725,579**

TAB 7

UNDERTAKING – TCJ1.7

Undertaking

To provide answers to the VECC questions filed September 19.

Response

VECC-43

Reference: Exhibit I/Tab1/Schedule 144, page 2, lines 5-7 / OEB Decision, EB-2006-0501, Page 91

Preamble: EB-2006-0501 Decision states: The Board agrees with the consumer group intervenors with respect to the impact of demand response programs. Hydro One's base forecast is weather-normal, which means that extreme weather events are excluded. It would seem logical to reduce the impact of demand response programs, which are most effective in extreme weather situations, when adjusting a weather-normal forecast.

a) Please confirm that Hydro One has exclude DR savings from its load forecast consistent with the Board's decision in EB-2006-0501.

Response:

a) In EB-2006-0501, the Board directed Hydro One to reduce the expected impact of CDM on total Ontario peak demand by 350MW to address a variety of issues raised during the proceeding. In the EB-2006-0501 proceeding, the CDM information used was from the OPA's Integrated Power System Plan (1.0).

   In Hydro One's current application, Hydro One's CDM information was based on the OPA's 2013 *Long-term Energy Plan* ("2013 LTEP") and Hydro One's discussion with the IESO. In the 2013 LTEP, there is no change in CDM peak impact from DR sources between 2015 and 2018. As such, Hydro One used the DR impact reflected in the 2015 actual peak when establishing its 2017-2018 load forecast.

TAB 8

Table 1 - Productivity Savings Forecast Summary ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive Productivity						
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Progressive Productivity Placeholder	17	39	61	78	91	286

As noted in the table above, Hydro One has identified savings opportunities totalling approximately $704M over the 2020-2024 TSP period. This reflects Tier 1 Productivity savings only. There are $353M in capital productivity savings, $114M in OM&A productivity savings and $237M in undefined capital savings. This latter category of savings falls within “Progressive Productivity”. Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB’s decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned