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Frank D'Andrea
Vice President, Regulatory Affairs & Chief Risk Officer

BY COURIER

May 9, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2018-0130 - Hydro One Networks' 2019 Transmission Revenue Requirement

Pursuant to the Ontario Energy Board's (the "**OEB**") decision (the "**Decision**") on the 2019 transmission revenue requirements for Hydro One Networks Inc. ("**Hydro One**") in the above-noted proceeding please find attached:

a) An implementation memo describing the implementation of the Decision;
b) Exhibits including a draft revenue requirement/charge determinant order, draft UTR order and supporting schedules, reflecting the specific directions provided in the Decision; and
c) An accounting order for the Other Post-Employment Benefit (OPEB) Cost Deferral Account.

The OEB's proposed 2019 rates revenue requirement[1] has been updated to $1,568.9 million[2] reflecting the corrected Bill 2 adjustment,[3] annualizing the Regulatory Account Balance credit[4] and inclusion of Foregone Revenue.[5]

The 2019 UTRs in $/kW-Month are $3.83 for Network, $0.96 for Line Connection and $2.30 for Transformation Connection.[6] The calculation of the 2019 UTRs, wholesale meter rates, low

[1] EB-2018-0130 Decision, April 25, 2019, p 17.
[2] Exhibit 6.0 2019 Revenue Requirement by Rate Pool (Including Annualized Regulatory Asset Balance and Foregone Revenue)
[3] EB-2018-0130 Hydro One Implementation of Decision Memo Section 3, p 2.
[4] EB-2018-0130 Hydro One Implementation of Decision Memo Section 4.1, p 3.
[5] EB-2018-0130 Hydro One Implementation of Decision Memo Section 4.3, p 4.
[6] Exhibit 7.0 Final Uniform Transmission Rates and Revenue Disbursement Allocators (Including Foregone Revenue)

voltage switchgear credit, charge determinants, revenue disbursement allocators, foregone revenue calculation, and bill impacts resulting from the OEB's findings are detailed in Exhibits 1.0 to 8.0. The revenue requirement and charge determinants used for other Ontario transmitters in calculating the 2019 UTRs reflect their current OEB-approved values as shown in Exhibits 4.0 and 7.0.

By copy of this letter, we are notifying all intervenors, OEB staff and other Ontario transmitters of this filing and of the fact that they have the opportunity to submit comments, if any, to the OEB by May 23, 2019 on the draft revenue requirement/charge determinant order, the draft UTR order and supporting schedules.

If you have any questions regarding this submission, please contact Linda Gibbons at (416) 345-4373.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Encls.
cc. EB-2018-0130 parties (electronic)

Implementation of Decision

May 9, 2019

On April 25th, 2019, the OEB issued its decision (the "**Decision**") on Hydro One's application for 2019 electricity transmission revenue requirement (EB-2018-0130). The Decision is effective as of May 1, 2019.[1] The OEB directed Hydro One to file a draft revenue requirement/charge determinant order, draft UTR order and supporting schedules reflecting the OEB's findings (collectively, "**Draft Order**") by May 9, 2019.

This memo explains how Hydro One has implemented the changes ordered by the OEB in its Draft Order.

1. Determination of Revenue Requirement

Hydro One's proposed rates revenue requirement of $1,550.2 million for 2019,[2] has been updated to $1,552.4 million based on the Decision.[3] The derivation of this revenue is provided in Exhibit 1.0 and includes the following approvals and adjustments:

- Revenue Cap Index (RCI) set at 1.4%;[4]
- $1.02 Million reduction to the 2018 Revenue Requiprement for Bill 2 adjustments related to executive compensation – explained in section 3 below;[5]
- The disposition of regulatory account balances totaling $37.6 million over the eight-month period from May 1, 2019 to December 31, 2019;[6]
- Adjustment of Base Revenue Requirement by the RCI consistent with Table 2 of

[1] EB-2018-0130 Decision, April 25 2019, p 20.
[2] Exhibit A-7-1 p 2.
[3] The approved rates revenue requirement of $1,552.4 million has been adjusted to $1,557.8 million to account for the annualized Regulaotry Account balance as explained in Section 4.1, and further adjusted to $1568.9M to account for the annualized foregone revenue for May and June 2019 as explained in Section 4.2.
[4] EB-2018-0130 Decision, April 25 2019, p 6.
[5] *Ibid* p 9.

the Decision;[7] and

- Adjustment of the low voltage switchgear (LVSG) credit, but not the export transmission service (ETS) revenue by the RCI.[8]

2. Other OEB Determinations

The Decision made the following additional determinations:

- Discontinuance of the Foregone Revenue Deferal Account and inapplicability of the In-service Capital Additions Variance Account for 2019 capital additions;[9]
- Continuation of the Other Post-Employment Benefit Cost Deferral Account;[10]
- Denied approval of a new Revenue Cap Index Parameters Differential Account;[11]
- Maintaining the 2018 charge determinants approved in EB-2016-0160;[12] and
- Allocation of revenue requirement by rate pool as revised by Hydro One in Staff Interrogatory #3.[13]

3. Bill 2 Adjustments Related to Executive Compensation

The OEB found Hydro One's proposed approach to address the Hydro One Accountability Act (HOAA) to be reasonable and consistent with the OEB's recent decision for Hydro One's distribution business.[14] The Decision provided a Bill 2 Adjustment amount of $1.095 million applied to the 2018 Revenue Requirement.[15]

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[6] *Ibid* p 11.
[7] *Ibid* p 17.
[8] *Ibid*, p 16-17.
[9] *Ibid*, p 13.
[10] *Ibid* p 14.
[11] *Ibid* p 15.
[12] *Ibid* p 18.
[13] *Ibid* p 19.
[14] *Ibid* p 7.
[15] *Ibid* p 17.

Hydro One has corrected the Bill 2 Adjustment amount to $1.02 million[16] consistent with evidence provided during the proceeding.[17]

4. UTR Calculations

The following items have been considered in calculating the final 2019 Uniform Transmission Rates (UTR)[18]:

- The effective date of May 1, 2019 for the approved revenue requirement;
- The implementation date for final 2019 UTRs of July 1, 2019, as confirmed by OEB Staff;
- Collection of the foregone revenue for the period between the May 1, 2019 effective date and the July 1, 2019 implementation date; and
- Disposition of the approved regulatory account balance taking into account that the current interim 2019 UTRs include a previously approved regulatory account disposition.

4.1 Disposition of Regulatory Account Balances

The Decision approved the disposition of a regulatory account credit balance of $37.6 million in 2019. The interim 2019 UTRs (effective from January 1 to April 30, 2019) included the disposition of a credit of $47.8 million in regulatory accounts. Therefore, Hydro One has already refunded $15.9 million (one third of $47.8 million) in regulatory accounts during the first four months of 2019. Therefore, as of the effective date of May 1, 2019 Hydro One will need to refund $21.7 million ($37.6 million - $15.9 million) of the approved 2019 regulatory account balance over the remaining eight months of 2019 (May to December). This will ensure that the total regulatory account balance refunded

[16] Exhibit 1.0 Approved 2019 Revenue Requirement
[17] Exhibit A-7-1, Table 1, p 2 ($962,852) plus Hydro One Reply Submission p 12 ($55,400).
[18] Exhibit 7.0 Final 2019 UTR and Revenue Disbursement Allocators (Including Foregone Revenue)

to transmission customers in 2019 is $37.6 million.[19]

The calculation for UTRs is based on a 12-month recovery period requiring the regulatory account balance added to rates revenue requirement to be annualized. The derivation of the annualized equivalent of refunding $21.7 million over May 1 to December 31, 2019 is shown in Table 1.

Table 1: Derivation of Annualized Regulatory Account Balance

Rate Pool	Total Annual Charge Determinants (A)[20]	Total Charge Determinants for May to Dec (B)[21]	Regulatory Account Balance to be Refunded between May 1st and Dec 31st 2019 (C)[22]	Annualized Regulatory Account Balance (D=A/B*C)
Network	249,176	167,786	($14,132,424)	($20,987,789)
Line Connection	240,481	162,766	($2,545,854)	($3,761,402)
Transformation Connection	203,768	137,673	($5,013,861)	($7,420,934)
			($21,692,139)	**($32,170,125)**

The rates revenue requirement including the annualized regulatory account balance is $1,557.8 million as shown in Exhibit 2.0. UTRs based on this rates revenue requirement will result in the remaining $21.7 million being disposed of over the eight-month period starting May 1, 2019.

The UTRs calculated using the rates revenue revenue requirement from Exhibit 2.0 are shown in Exhibit 4.0. These UTRs are used for determining the forgone revenue, as discussed in Section 4.2.

[19] EB-2018-0130 Decision, April 25 2019, p 11.
[20] Exhibit 5.0 2019 Foregone Revenue Calculations Table 1.
[21] *Ibid* Table 3.
[22] Split among the rate pools uses the same methodology as provided in 2018 Hydro One Revenue Requirement Draft Rate Order Exhibit 2.0, filed Dec 4, 2017.

4.2 Foregone Revenue Calculation

OEB staff has confirmed that the new UTRs will be implemented as of July 1, 2019 and has indicated that it would be appropriate for Hydro One to recover the foregone revenue for the period between the May 1, 2019 effective date and the July 1, 2019 implementation date.

The foregone revenue amount is calculated on a monthly basis using the total monthly charge determinants for each UTR rate pool, which are consistent with Hydro One's annual charge determinants approved in the Decision, as shown in Exhibit 3.0.

The monthly foregone revenue amount is the difference between the revenue collected under the approved 2019 Interim UTRs (EB-2018-0326) and the revenue collected under the 2019 UTRs provided in Exhibit 4.0. The total foregone revenue for May and June 2019 is $5.6 million as determined in Exhibit 5.0.

Hydro One proposes to recover the foregone revenue of $5.6 million over the July 1 to December 31, 2019 period. Since the UTRs calculations are based on a 12-month recovery period, the foregone revenue to be added to the rates revenue requirement has been annualized as shown in Table 2.

Table 2: Derivation of Annualized Foregone Revenue

Rate Pool	Total Annual Charge Determinanats (A)[23]	Total Charge Determinants for Jul-Dec (B)[24]	Foregone Revenue for May and June 2019 (C)[25]	Annualized Foregone Revenue (D=A/B*C)
Network	249,176	125,698	$3,782,914	$7,499,033
Line Connection	240,481	122,225	$421,174	$828,668
Transformation Connection	203,768	103,138	$1,395,483	$2,757,020
			$5,599,571	**$11,084,721**

Including the annualized foregone revenue amount of $11.1 million in determining the final 2019 UTRs ensures that Hydro One recovers the foregone revenue of $5.6M over the remaining six months of 2019, starting from the July 1, 2019 implementation date.

The final 2019 rates revenue requirement by rate pool including the foregone revenue determined in Table 2, is $1,568.9 million as shown in Exhibit 6.0. This rates revenue requirement, is used to calculate the final 2019 UTRs which are provided in Exhibit 7.0.

Exhibit 7.1 provides the proposed 2019 UTR Tariff reflecting the UTRs calculated in Exhibit 7.0. The expected bill impacts on typical transmission and distribution customers resulting from the 2019 UTRs provided in Exhibit 4.0, are shown in Exhibit 8.0.

[23] Exhibit 5.0 2019 Foregone Revenue Calculations Table 1.
[24] *Ibid* Table 3.
[25] *Ibid* Table 8.

5.0 Supporting Material

The detailed information supporting the determination of the revenue requirement and charge determinants are provided in the attached Exhibits:

EXHIBIT		TITLE
1.0		Approved 2019 Revenue Requirement
2.0		2019 Rates Revenue Requirement by Rate Pool (Including Annualized Regulatory Account Balance)
3.0		2019 Hydro One Networks Inc Charge Determinants
4.0		2019 UTRs and Revenue Disbursement Allocators (Excluding Foregone Revenue)
5.0		2019 Foregone Revenue Calculations
6.0		2019 Rates Revenue Requirement by Rate Pool (Including Annualized Regulatory Asset Balance and Foregone Revenue)
7.0		Final 2019 UTRs and Revenue Disbursement Allocators (Including Foregone Revenue)
	7.1	2019 Ontario Uniform Transmission Rates Schedules
8.0		2019 Bill Impacts (Excluding Foregone Revenue)
9.0		2019 Wholesale Meter Service and Exit Fee Schedule
10.0		Accounting Order
	10.1	Accounting Order for OPEB Cost Deferral Account

Hydro One Netowrks Inc.
Approved 2019 Revenue Requirement

	2018 Amounts	Adjustments for 2019	2019 Amounts
Total Approved Revenue Requirement (excluding Bill 2 adjustments)	$1,623,777,363		
Bill 2 Adjustments(1)	-$1,018,252		
Total Revenue Requirement (including Bill 2 adjustments)(2)	$1,622,759,112		$1,644,514,168
Deduct: External Revenue	-$28,500,000	Same as approved 2018 amount	-$28,500,000
Deduct: WMS Revenue	-$276,500	Same as approved 2018 amount	-$276,500
Deduct: Export Tx Service Revenue	-$40,050,000	Same as approved 2018 amount	-$40,050,000
Base Revenue Requirement	$1,553,932,612	1.4%	$1,575,687,668
Deduct: Regulatory Assets Credit	-$47,800,000	Per OEB Decision	-$37,628,098
Add: Foregone Revenue	-$10,571,073	Not Applicable	$0
Add: LVSG Credit	$14,129,893	1.4%	$14,327,712
Rates Revenue Requirement	**$1,509,691,432**		**$1,552,387,282**

(1) *Refer to Implementation Memo for further details*
(2) *Total 2019 Revenue Requirement is determined based on approved 2019 Base Revenue Requirement plus approved 2018 External Revenue, WMS Revenue, and Export TX Service Revenue.*

Hydro One Networks Inc.

2019 Rates Revenue Requirement by Rate Pool (Including Annualized Regulatory Account Balance)

	Note	Network	Line Connection	Transformation Connection	Uniform Transmission Rates
2018 DRO Total Revenue Requirement	*1*	950,018,214	226,899,068	446,860,081	1,623,777,363
Percentage Split by Rate pool		59%	14%	28%	100%
2019 Total Revenue Requirement	*2*	962,150,630	229,796,733	452,566,805	1,644,514,168
Less External Revenues		(16,674,404)	(3,982,457)	(7,843,139)	(28,500,000)
Less WMS Revenue				(276,500)	(276,500)
Less Export Revenues		(40,050,000)			(40,050,000)
Base Revenue Requirement		905,426,227	225,814,276	444,447,166	1,575,687,668
Less Regulatory Asset Balance	*3,4*	(20,987,789)	(3,761,402)	(7,420,934)	(32,170,125)
Plus LVSG Credit	*5*			14,327,712	14,327,712
Total Rates Revenue Requirement		**884,438,437**	**222,052,874**	**451,353,944**	**1,557,845,255**

Note 1: Per 2018 Hydro One Revenue Requirement Draft Rate Order Exhibit 2.0, filed Dec 4, 2017

Note 2: Use the OEB-approved 2018 split of total revenue requirement by rate pool to allocate the 2019 total revenue requirement among the three transmission rate pool.

Note 3: As explained in the Implementation Memo, -$32.2M is the annualized equivalent of -$21.7M to be refunded through UTRs between May and December 2019.

Note 4: Use the same methodology as in 2018 Hydro One Revenue Requirement Draft Rate Order Exhibit 2.0, filed Dec 4, 2017. i.e. Excess Export Service Revenue (Account 2405) is directly allocated to Network pool, all other accounts are allocated based on total revenue requirement split by rate pools.

Note 5: Approved 2018 amount (per 2018 Hydro One Revenue Requirement Draft Rate Order) increased by the RCI factor of 1.4%.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2018-0130

Summary Charge Determinants
(for Setting Uniform Transmission Rates effective May 1, 2019 to December 31, 2019)

	2019 Total Annual MW
Network	244,924.157
Line Connection	236,948.242
Transformation Connection	202,510.123

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2018-0130

Uniform Transmission Rates and Revenue Disbursement Allocators **(Excluding Foregone Revenue)**
(for Period May 1, 2019 to December 31, 2019)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,535,095	$1,138,610	$2,314,387	$7,988,092
CNPI	$2,638,364	$662,405	$1,346,432	$4,647,201
H1N SSM	$22,583,307	$5,669,912	$11,524,900	$39,778,120
H1N	$884,438,437	$222,052,874	$451,353,944	$1,557,845,255
B2MLP	$32,789,151	$0	$0	$32,789,151
All Transmitters	$946,984,354	$229,523,801	$466,539,663	$1,643,047,819

Transmitter	Total Annual Charge Determinants (MW)**			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.80**	**0.95**	**2.29**	
FNEI Allocation Factor	**0.00479**	**0.00496**	**0.00496**	
CNPI Allocation Factor	**0.00279**	**0.00289**	**0.00289**	
H1N SSM Allocation Factor	**0.02385**	**0.02470**	**0.02470**	
H1N Allocation Factor	**0.93395**	**0.96745**	**0.96745**	
B2MLP Allocation Factor	**0.03462**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

** The sum of 12 monthly charge determinants for the year.

Note 1: FNEI 2018 Rates Revenue Requirement and Charge Determinant Order EB-2016-0231 dated January 18, 2018.
Note 2: CNPI 2016 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354, dated January 14, 2016.
Note 3: H1N SSM Interim 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0218, issued December 6, 2018.
Note 4: H1N 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0130 dated April 25, 2019. (per Exhibits 2.0 and 3.0)

Note 5: B2M LP 2019 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.

Note 6: Calculated data in shaded cells.

2019 Foregone Revenue Calculations

Table 1. HONI Transmission Approved Charge Determinant Forecast for the Year 2019, After Deducting the Load Impact of CDM and Embedded Generation (MW)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	21,086	20,563	20,273	18,078	19,388	21,982	22,839	21,934	20,202	18,239	19,540	20,800	244,924
Line Connection	20,143	19,733	19,312	17,385	19,007	20,938	22,166	21,145	19,652	18,034	18,882	20,552	236,948
Transformation Connection	17,268	16,977	16,649	14,792	16,308	18,014	19,108	18,100	17,146	14,832	15,866	17,451	202,510

Table 2. Monthly Charge Determinant Share of Annual Total

% Share	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	8.61%	8.40%	8.28%	7.38%	7.92%	8.98%	9.32%	8.96%	8.25%	7.45%	7.98%	8.49%	100.00%
Line Connection	8.50%	8.33%	8.15%	7.34%	8.02%	8.84%	9.35%	8.92%	8.29%	7.61%	7.97%	8.67%	100.00%
Transformation Connection	8.53%	8.38%	8.22%	7.30%	8.05%	8.90%	9.44%	8.94%	8.47%	7.32%	7.83%	8.62%	100.00%

Table 3. 2019 Interim UTR Charge Determinant (including all Transmitters)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	21,452	20,920	20,625	18,392	19,725	22,364	23,235	22,315	20,553	18,555	19,879	21,161	249,176
Line Connection	20,444	20,027	19,600	17,644	19,290	21,250	22,496	21,460	19,945	18,302	19,164	20,858	240,481
Transformation Connection	17,375	17,083	16,753	14,884	16,409	18,126	19,226	18,212	17,252	14,924	15,965	17,559	203,768

Table 4. Interim 2019 UTR

	$/kw-month	Hydro One Revenue Allocators
Network	3.71	0.93238
Line Connection	0.94	0.96669
Transformation Connection	2.25	0.96669

Table 5. 2019 Revenue at 2019 Interim UTR and 2019 Charge Determinants ($M) (3*4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	74.2	72.4	71.3	63.6	68.2	77.4	80.4	77.2	71.1	64.2	68.8	73.2	861.9
Line Connection	18.6	18.2	17.8	16.0	17.5	19.3	20.4	19.5	18.1	16.6	17.4	19.0	218.5
Transformation Connection	37.8	37.2	36.4	32.4	35.7	39.4	41.8	39.6	37.5	32.5	34.7	38.2	443.2
Total	**130.6**	**127.7**	**125.6**	**112.0**	**121.4**	**136.1**	**142.6**	**136.3**	**126.7**	**113.3**	**120.9**	**130.3**	**1,523.7**
						257.5							

Table 6. Proposed 2019 UTR

	$/kw-month	Hydro One Revenue Allocators
Network	3.80	0.93395
Line Connection	0.95	0.96745
Transformation Connection	2.29	0.96745

Table 7. 2019 Revenue at Proposed 2019 UTR and 2019 Charge Determinants ($M) (3*6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	76.1	74.2	73.2	65.3	70.0	79.4	82.5	79.2	72.9	65.9	70.6	75.1	884.3
Line Connection	18.8	18.4	18.0	16.2	17.7	19.5	20.7	19.7	18.3	16.8	17.6	19.2	221.0
Transformation Connection	38.5	37.8	37.1	33.0	36.4	40.2	42.6	40.3	38.2	33.1	35.4	38.9	451.4
Total	**133.4**	**130.5**	**128.3**	**114.5**	**124.1**	**139.1**	**145.7**	**139.3**	**129.5**	**115.7**	**123.5**	**133.2**	**1,556.8**
						263.1							

Table 8. 2019 Forgone Revenue (Rev at Proposed Rates - Rev at Interim Rates) ($M) (7-5)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	1.9	1.9	1.9	1.7	1.8	2.0	2.1	2.0	1.8	1.7	1.8	1.9	22.4
Line Connection	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.5
Transformation Connection	0.7	0.7	0.7	0.6	0.7	0.7	0.8	0.7	0.7	0.6	0.6	0.7	8.2
Total	**2.8**	**2.8**	**2.7**	**2.4**	**2.6**	**3.0**	**3.1**	**3.0**	**2.8**	**2.5**	**2.6**	**2.8**	**33.1**

Hydro One Networks Inc.

2019 Rates Revenue Requirement by Rate Pool (Including Annualized Regulatory Asset Balance and Foregone Revenue)

	Note	Network	Line Connection	Transformation Connection	Uniform Transmission Rates
2018 DRO Total Revenue Requirement	*1*	950,018,214	226,899,068	446,860,081	1,623,777,363
Percentage Split by Rate pool		59%	14%	28%	100%
2019 Total Revenue Requirement	*2*	962,150,630	229,796,733	452,566,805	1,644,514,168
Less External Revenues		(16,674,404)	(3,982,457)	(7,843,139)	(28,500,000)
Less WMS Revenue				(276,500)	(276,500)
Less Export Revenues		(40,050,000)			(40,050,000)
Base Revenue Requirement		905,426,227	225,814,276	444,447,166	1,575,687,668
Less Regulatory Asset Balance	*3,4*	(20,987,789)	(3,761,402)	(7,420,934)	(32,170,125)
Plus LVSG Credit	*5*			14,327,712	14,327,712
Sub-Total Rates Revenue Requirement		**884,438,437**	**222,052,874**	**451,353,944**	**1,557,845,255**
Annualized Foregone Revenue	*6*	7,499,033	828,668	2,757,020	11,084,721
Total Rates Revenue Requirement		**891,937,471**	**222,881,542**	**454,110,964**	**1,568,929,976**

Note 1: Per 2018 Hydro One Revenue Requirement Draft Rate Order Exhibit 2.0, filed Dec 4, 2017
Note 2: Use the OEB-approved 2018 split of total revenue requirement by rate pool to allocate the 2019 total revenue requirement among the three transmission rate pool.

Note 3: As explained in the Implementation Memo, -$32.2M is the annualized equivalent of -$21.7M to be refunded through UTRs between May and December 2019.

Note 4: Use the same methodology as in 2018 Hydro One Revenue Requirement Draft Rate Order Exhibit 2.0, filed Dec 4, 2017. i.e. Excess Export Service Revenue (Account 2405) is directly allocated to Network pool, all other accounts are allocated based on total revenue requirement split by rate pools.

Note 5: Approved 2018 amount (per 2018 Hydro One Revenue Requirement Draft Rate Order) increased by the RCI factor of 1.4%.
Note 6: As explained in the Implementation Memo, Foregone Revenue calculated in Exhibit 5.0 has been annualized, which essentially doubles it from $5.6 million to $11.1 million.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2018-0130

Final Uniform Transmission Rates and Revenue Disbursement Allocators **(Including Foregone Revenue)**
(for Period Jul 1, 2019 to December 31, 2019)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,541,234	$1,134,785	$2,312,073	$7,988,092
CNPI	$2,641,936	$660,179	$1,345,085	$4,647,201
H1N SSM	$22,613,881	$5,650,863	$11,513,376	$39,778,120
H1N	$891,937,471	$222,881,542	$454,110,964	$1,568,929,976
B2MLP	$32,789,151	$0	$0	$32,789,151
All Transmitters	$954,523,673	$230,327,370	$469,281,498	$1,654,132,540

Transmitter	Total Annual Charge Determinants (MW)**			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.83**	**0.96**	**2.30**	
FNEI Allocation Factor	**0.00476**	**0.00493**	**0.00493**	
CNPI Allocation Factor	**0.00277**	**0.00287**	**0.00287**	
H1N SSM Allocation Factor	**0.02369**	**0.02453**	**0.02453**	
H1N Allocation Factor	**0.93443**	**0.96767**	**0.96767**	
B2MLP Allocation Factor	**0.03435**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

** The sum of 12 monthly charge determinants for the year.

Note 1: FNEI 2018 Rates Revenue Requirement and Charge Determinant Order EB-2016-0231 dated January 18, 2018.
Note 2: CNPI 2016 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354, dated January 14, 2016.
Note 3: H1N SSM Interim 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0218, issued December 6, 2018.
Note 4: H1N 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0130 dated April 25, 2019. (per Exhibits 6.0 and 3.0)
Note 5: B2M LP 2019 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.
Note 6: Calculated data in shaded cells.

2019 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2018-0130

The rate schedules contained herein shall be implemented as of July 1, 2019

Issued: May, 2019
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**3.83**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.96**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.30**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Table 1: Average Bill Impacts on Transmission and Distribution-connected Customers (Excluding Foregone Revenue)

Description	**2018**	**2019**
Rates Revenue Requirement ($M)	$1,510.7	$1,557.8
Net Impact on Average Transmission Rates		3.1%
Transmission as a % of Tx-connected customer's Total Bill		7.4%
Estimated Average Bill impact for a Tx-Connected Customer		0.2%
Transmission as a % of Dx-connected customer's Total Bill		6.2%
Estimated Average Bill impact for a Dx-Connected Customer		0.2%

Table 2: Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$121.75	$236.81
RTSR included in 2018 R1 Customer's Bill (based on 2016 UTR)	$4.78	$8.96	$21.50
Estimated 2017 Monthly RTSR [2]	$4.74	$8.89	$21.33
2017 change in Monthly Bill	**($0.04)**	**($0.07)**	**($0.16)**
2017 change as a % of total bill	*0.0%*	*-0.1%*	*-0.1%*
Estimated 2018 Monthly RTSR [3]	$4.97	$9.32	$22.36
2018 change in Monthly Bill	**$0.23**	**$0.43**	**$1.03**
2018 change as a % of total bill	*0.3%*	*0.4%*	*0.4%*
Estimated 2019 Monthly RTSR [4]	$5.12	$9.59	$23.02
2019 change in Monthly Bill	**$0.15**	**$0.28**	**$0.66**
2019 change as a % of total bill	*0.2%*	*0.2%*	*0.3%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all applicable components of the Fair Hydro Plan).

[2]2017 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017.

[3]2018 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2018.

[4]The impact on RTSR is assumed to be the net impact on average Transmission rates adjusted for Hydro One's revenue disbursement allocator per approved 2019 Interim UTRs.

Table 3: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$198.93	$367.73	$2,562.20
RTSR included in 2018 GSe Customer's Bill (based on 2016 UTR)	$10.63	$21.26	$159.47
Estimated 2017 Monthly RTSR [2]	$10.55	$21.10	$158.25
2017 change in Monthly Bill	**($0.08)**	**($0.16)**	**($1.22)**
2017 change as a % of total bill	*0.0%*	*0.0%*	*0.0%*
Estimated 2018 Monthly RTSR [3]	$11.06	$22.12	$165.89
2018 change in Monthly Bill	**$0.51**	**$1.02**	**$7.64**
2018 change as a % of total bill	*0.3%*	*0.3%*	*0.3%*
Estimated 2019 Monthly RTSR [4]	$11.39	$22.77	$170.79
2019 change in Monthly Bill	**$0.33**	**$0.65**	**$4.90**
2019 change as a % of total bill	*0.2%*	*0.2%*	*0.2%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all applicable components of the Fair Hydro Plan).

[2]2017 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017.

[3]2018 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2018.

[4]The impact on RTSR is assumed to be the net impact on average Transmission rates adjusted for Hydro One's revenue disbursement allocator per approved 2019 Interim UTRs.

HYDRO ONE NETWORKS INC.
WHOLESALE METER SERVICE
AND EXIT FEE SCHEDULE

HYDRO ONE NETWORKS - WHOLESALE METER SERVICE

APPLICABILITY:

This fee schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

a) Fee for Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual fee of $7,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

This Wholesale Meter Service annual fee shall remain in place until all the remaining meter points exit the transitional arrangement.

b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

ACCOUNTING ORDER

In the Decision, the OEB directed Hydro One to provide a draft Accounting Order for the OPEB Cost Deferral Account. To comply with the OEB's direction, Hydro One has provided the draft accounting order in Exhibit 10.1.

ACCOUNTING ENTRIES
OPEB COST DEFERRAL ACCOUNT

The OPEB Cost Deferral Account will record all elements of the net periodic benefit cost other than the service cost that would have been classified as capital prior to the adoption of ASU 2017-07.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account “OPEB Cost Deferral Account” effective January 1, 2018 until such time as the effective date of the next transmission rebasing application. Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The approach to disposition of the deferral account will be determined by the OEB in a future proceeding. The final determination on the calculation and treatment of interest will be made in conjunction with the decision on the approach to disposition of the deferral account.

The following outlines the proposed accounting entries for this account:

USofA #	**Account Description**
Dr: 1508	Other Regulatory Assets – Sub-Account “OPEB Cost Deferral Account”
Cr: 2055	Construction Work In Progress - Electric

To record the capitalized elements of the net periodic post-retirement benefit cost other than service cost.

USofA #	**Account Description**
Dr: 1508	Other Regulatory Assets – Sub-Account "OPEB Cost Deferral Account"
Cr: 6035	Other Interest Expense

To record interest improvement on the principal balance of the "OPEB Cost Deferral Account".