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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

December 9, 2014

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

Dear Ms. Walli:

EB-2014-0140 - Hydro One Networks' 2015-2016 Transmission Revenue Requirement & Charge Determinants
EB-2014-0357 - 2015 Uniform Transmission Rates

Please find attached a draft rate order that implements the Ontario Energy Board's ("**the Board**") December 2, 2014 oral decision accepting the Settlement Agreement on the 2015 & 2016 transmission revenue requirement for Hydro One Networks Inc. ("**Hydro One**").

The draft rate order reflects the outcome of the Settlement Agreement as well as the impact of changes to the cost of capital parameters released by the Board on November 20, 2014, the actual Hydro One long-term debt issued in 2014, and the updated forecast for 2015 and 2016 long-term debt coupon rates. The 2015 proposed revenue requirement of $1,617.1 million has been reduced to $1,567.8 million, and the 2016 proposed revenue requirement of $1,689.2 million has been reduced to $1,644.8 million. The 2016 proposed revenue requirement will be further updated to reflect the Board's November 2015 cost of capital parameters as part of preparing the 2016 draft rate order. The underlying assumptions and revenue requirement calculations are set out in the attached supporting documentation Exhibits 1.0 to 1.8.

For the purpose of determining the 2015 Uniform Transmission Rates ("**UTRs**"), the draft rate order also provides Hydro One's revenue requirement excluding the costs being shifted to the B2M Limited Partnership ("**B2M LP**") as set out in Exhibits 2.0 and 4.0. The B2M LP information is based on their October 24, 2014 application for interim revenue requirement revised to reflect the updated cost of capital parameters as per the B2M LP Revised Exhibit A (Annualized Revenue Requirement for 2015) filed on December 4, 2014.

The 2015 UTRs in $/kW-Month are determined to be $3.77 for Network, $0.86 for Line Connection and $2.00 for Transformation Connection. The calculation of the 2015 UTRs, wholesale meter rates, low voltage switchgear credit, charge determinants and revenue disbursement allocators resulting from the Board's findings are detailed in Exhibits 3.0 to 8.0. The revenue requirement and charge determinants used for other Ontario transmitters in calculating the 2015 UTRs reflect their current Board approved values and are set out in Exhibit 6.1.

As directed by the Board, by copy of this letter, we are notifying all intervenors of this draft rate order filing and of the fact that they have the opportunity to submit comments, if any, to the Board within 7 calendar days from today.

If you have any questions regarding this submission, please contact Erin Henderson at (416) 345-4479.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Encls.

cc. EB-2014-0140 Intervenors (electronic) hydro one

TABLE OF CONTENTS
EB-2014-0140 / EB-2014-0357
REVENUE REQUIREMENT, CHARGE DETERMINANTS & OTHER

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Revenue Requirement Summary Prior to Excluding B2M LP

($ millions)	**Supporting Reference**	**Hydro One Proposed 2015**	**Hydro One Proposed 2016**	**Settlement Impact 2015**	**Settlement Impact 2016**	**Cost of Capital Update 2015**	**Cost of Capital Update 2016**	**OEB Approved 2015**	**OEB Approved 2016**
OM&A	Exhibit 1.1	452.0	457.4	(20.0)	(20.0)	-	-	432.0	437.4
Depreciation	Exhibit 1.2	394.2	404.0	-	-	-	-	394.2	404.0
Return on Debt	Exhibit 1.4	304.0	324.3	(6.6)	(6.9)	0.0	(1.5)	297.4	316.0
Return on Equity	Exhibit 1.4	395.3	420.6	(10.2)	(2.2)	(6.5)	(9.7)	378.5	408.8
Income Tax	Exhibit 1.5	71.8	82.8	(3.7)	(0.8)	(2.3)	(3.5)	65.7	78.6
Base Revenue Requirement		**1,617.1**	**1,689.2**	**(40.5)**	**(29.8)**	**(8.9)**	**(14.7)**	**1,567.8**	**1,644.8**
Deduct: External Revenue	Exhibit 1.6	(28.4)	(28.8)	(3.4)	(3.4)	-	-	(31.8)	(32.2)
Subtotal		**1,588.7**	**1,660.4**	**(43.9)**	**(33.2)**	**(8.9)**	**(14.7)**	**1,536.0**	**1,612.6**
Deduct: Export Tx Service Revenue	Exhibit 1.7	(33.4)	(34.3)	2.5	2.6	-	-	(30.9)	(31.7)
Deduct: Other Cost Charges	Exhibit 1.8	(18.0)	(18.0)	18.0	(18.0)	0.0	0.0	0.0	(36.1)
Add: Low Voltage Switch Gear	Note 1	13.2	13.9	(0.3)	(0.4)	(0.1)	(0.2)	12.8	13.3
Rates Revenue Requirement		**1,550.5**	**1,622.0**	**(23.7)**	**(49.0)**	**(9.0)**	**(14.9)**	**1,517.9**	**1,558.1**

Note 1: The value of $13.3M for LVSG in 2016 is an estimate and will be revised once the 2016 Revenue Requirement is finalized in the fall of 2015.
Note 2: The 2015 Cost of Capital is updated to reflect OEB approved parameters issued on November 20, 2014, updated forecast 2015 and 2016 third-party long-term debt rate and 2014 actual debt issues.
Note 3: As per Hydro One's Settlement Agreement approved by the Board on December 2, 2014, the refund of Regulatory Accounts in the amount of $18.0M in 2015 is postponed to 2016 to smooth the rate impact.
Note 4: The Export Tx Service Revenue credit is decreased by $2.5M in 2015 and $2.6M in 2016 as per Hydro One's Settlement Agreement approved by the Board on December 2, 2014.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

OM&A

($ millions)	Supporting Reference	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
OM&A	*See Note 1*	452.0	457.4	(20.0)	(20.0)	-	-	432.0	437.4

Note 1: As per Hydro One's Settlement Agreement approved by the Board on December 2, 2014, OM&A expenses are reduced by $20M in 2015 and $20M in 2016 from Hydro One's application filed on June 27, 2014.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Rate Base and Depreciation

($ millions)	Supporting Reference	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
Rate Base	*See supporting details below*	10,176.5	10,558.0	(1.2)	(1.1)	-	-	10,175.3	10,556.9
Depreciation	*See supporting details below*	394.2	404.0	-	-	-	-	394.2	404.0

OEB Decision Impact Supporting Details	Reference	2015 Detailed Computation	2016 Detailed Computation	2015 Rate Base Impact	2016 Rate Base Impact	2015 Depreciation Impact	2016 Depreciation Impact
Working Capital Adjustment							
Rate Base Details	Pre-filed Evidence Exh D1-1-1						
Utility plant (average)							
Gross plant at cost		15,665.5	16,353.0				
Less: Accumulated depreciation		(5,515.7)	(5,819.3)				
Add: CWIP		-	-				
Net utility plant		10,149.9	10,533.7				
Working capital							
Cash working capital		12.9	10.3				
Materials & supplies inventory		13.7	14.0				
Total working capital		26.6	24.2				
Total Rate Base		10,176.5	10,558.0				
Working capital as % of OM&A	(a)	5.9%	5.3%				
OM&A Reduction per Settlement Agreement	Exhibit 1.1 (b)	(20.0)	(20.0)				
Working capital reduction	(c) = (a) x (b)	(1.2)	(1.1)	(1.2)	(1.1)		

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Capital Expenditures

($ millions)	Supporting Reference	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
Capital expenditures		899.4	866.3	-	-	-	-	899.4	866.3

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2014-0140

Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**Hydro One Proposed 2015**	**Hydro One Proposed 2016**	**Settlement Impact 2015**	**Settlement Impact 2016**	**Cost of Capital Update 2015**	**Cost of Capital Update 2016**	**OEB Approved 2015**	**OEB Approved 2016**
Return on Rate Base									Note 2
Rate Base	Exhibit 1.2	$ 10,176.5	$ 10,558.0	$ (1.2)	$ (1.1)	$ -	$ -	$ 10,175.2	$ 10,557.0
Capital Structure:									
Third-Party long-term debt		50.7%	51.0%	(0.0%)	(0.0%)	0.2%	0.2%	50.9%	51.2%
Deemed long-term debt		5.3%	5.0%	(0.0%)	(0.0%)	(0.2%)	(0.2%)	5.1%	4.8%
Short-term debt		4.0%	4.0%	(0.0%)	(0.0%)	0.0%	0.0%	4.0%	4.0%
Common equity		40.0%	40.0%	(0.0%)	(0.0%)	0.0%	0.0%	40.0%	40.0%
Capital Structure:									
Third-Party long-term debt	Exhibit 1.4.1 and 1.4.2	5,157.9	5,385.9	(0.6)	(0.5)	23.1	23.0	5,180.3	5,408.4
Deemed long-term debt		541.0	526.5	(0.1)	(0.1)	(23.0)	(23.0)	517.9	503.4
Short-term debt		407.1	422.3	(0.0)	(0.0)	(0.0)	0.0	407.0	422.3
Common equity		4,070.6	4,223.2	(0.5)	(0.4)	(0.0)	0.0	4,070.1	4,222.8
		10,176.5	**10,558.0**	**$ (1.2)**	**$ (1.1)**	**$ (0.0)**	**$ (0.0)**	**10,175.3**	**10,556.9**
Allowed Return:									
Third-Party long-term debt	Exhibit 1.4.1 & 1.4.2	5.02%	5.08%	(0.05%)	(0.08%)	0.01%	(0.03%)	4.98%	4.97%
Deemed long-term debt	Exhibit 1.4.1 & 1.4.2	5.02%	5.08%	(0.05%)	(0.08%)	0.01%	(0.03%)	4.98%	4.97%
Short-term debt	Note 1	3.19%	4.45%	(0.92%)	(0.45%)	(0.11%)	0.03%	2.16%	4.03%
Common equity	Note 1	9.71%	9.96%	(0.25%)	(0.05%)	(0.16%)	(0.23%)	9.30%	9.68%
Return on Capital:									
Third-Party long-term debt		258.9	273.7	(2.6)	(4.5)	1.6	(0.3)	257.9	269.0
Deemed long-term debt		27.2	26.8	(0.3)	(0.4)	(1.1)	(1.3)	25.8	25.0
Short-term debt		13.0	18.8	(3.8)	(1.9)	(0.5)	0.1	8.8	17.0
AFUDC return on Niagara Reinforcement Project	see below	5.0	5.0	(0.0)	(0.1)	0.0	(0.0)	4.9	4.9
Total return on debt		**$ 304.0**	**$ 324.3**	**$ (6.6)**	**$ (6.9)**	**$ 0.0**	**$ (1.5)**	**$ 297.4**	**$ 316.0**
Common equity		**$ 395.3**	**$ 420.6**	**$ (10.2)**	**$ (2.2)**	**$ (6.5)**	**$ (9.7)**	**$ 378.5**	**$ 408.8**
AFUDC return on Niagara Reinforcement Project									
CWIP		99.1	99.1	-	-	-	-	99.1	99.1
Deemed long-term debt		5.02%	5.08%	(0.05%)	(0.08%)	0.01%	(0.03%)	4.98%	4.97%
		5.0	5.0	(0.0)	(0.1)	0.0	(0.0)	4.9	4.9

Note 1: The approved rates follow the OEB's November 20, 2014 guidance on cost of capital parameters to reflect the September 2014 Consensus Forecast.

Note 2: The 2016 cost of capital parameters & impacts are based on the October 2014 long-term Consensus Forecast and are for illustrative purposes only. Hydro One will submit a 2016 draft rate order to the OEB reflecting the cost of capital parameters issued by the Board once the September 2015 Consensus Forecast becomes available. At that point the up-to-date cost of capital parameters will be applied to determine the 2016 amounts.

Note 3: As per EB-2008-0272 Decision with Reasons on May 28, 2009, page 54, the deemed long-term rate has been updated to reflect Hydro One's embedded long-term debt rate.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2015)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/14 ($Millions)	Total Amount Outstanding: at 12/31/15 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
20	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
21	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	0.0	103.8	3.1	
22	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
23	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
24	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
25	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
26	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
27	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
28	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
29	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
30	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
31	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	
32	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.44	4.32%	30.0	30.0	30.0	1.3	Note 1
33	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.40	4.21%	198.0	198.0	198.0	8.3	Note 1
34	15-Mar-15	4.771%	15-Mar-45	159.3	0.8	158.6	99.50	4.80%	0.0	159.3	122.6	5.9	Note 2
35	15-Jun-15	3.905%	15-Jun-25	159.3	0.8	158.6	99.50	3.97%	0.0	159.3	85.8	3.4	Note 2
36	15-Sep-15	3.046%	15-Sep-20	159.3	0.8	158.6	99.50	3.15%	0.0	159.3	49.0	1.5	Note 2
37		**Subtotal**							4969.1	5297.1	5180.3	253.4	
38		Treasury OM&A costs										1.6	
39		Other financing-related fees										2.9	
40		**Total**							4969.1	5297.1	5180.3	257.9	4.98%

Note 1: Updated to reflect actual 2014 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2015 as per the September 2014 Consensus Forecast

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2016)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/15 ($Millions)	Total Amount Outstanding: at 12/31/16 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	0.0	48.5	2.3	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	0.0	13.8	0.7	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
20	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
21	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
22	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
23	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
24	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
25	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
26	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
27	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
28	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
29	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
30	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	
31	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.44	4.32%	30.0	30.0	30.0	1.3	Note 1
32	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.40	4.21%	198.0	198.0	198.0	8.3	Note 1
33	15-Mar-15	4.771%	15-Mar-45	159.3	0.8	158.6	99.50	4.80%	159.3	159.3	159.3	7.7	Note 2
34	15-Jun-15	3.905%	15-Jun-25	159.3	0.8	158.6	99.50	3.97%	159.3	159.3	159.3	6.3	Note 2
35	15-Sep-15	3.046%	15-Sep-20	159.3	0.8	158.6	99.50	3.15%	159.3	159.3	159.3	5.0	Note 2
36	15-Mar-16	5.521%	15-Mar-46	197.5	1.0	196.5	99.50	5.56%	0.0	197.5	151.9	8.4	Note 3
37	15-Jun-16	4.655%	15-Jun-26	197.5	1.0	196.5	99.50	4.72%	0.0	197.5	106.3	5.0	Note 3
38	15-Sep-16	3.796%	15-Sep-21	197.5	1.0	196.5	99.50	3.91%	0.0	197.5	60.8	2.4	Note 3
39		**Subtotal**							5297.1	5619.5	5408.4	264.5	
40		Treasury OM&A costs										1.6	
41		Other financing-related fees										3.0	
42		**Total**							5297.1	5619.5	5408.4	269.0	4.97%

Note 1: Updated to reflect actual 2014 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2015 as per the September 2014 Consensus Forecast
Note 3: Updated to reflect the forecast coupon rates for 2016 as per the October 2014 long-term Consensus Forecast

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Income Tax

($ millions)	Supporting Reference	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
Income Taxes	*See supporting details below*	71.8	82.8	(3.7)	(0.8)	(2.3)	(3.5)	65.7	78.6

Income Tax Supporting Details			Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
Rate Base	Exhibit 1.2	a	$ 10,176.5	$ 10,558.0	$ (1.2)	$ (1.1)	$ -	$ -	$ 10,175.3	$ 10,556.9
Common Equity Capital Structure		b	40.0%	40.0%					40.0%	40.0%
Return on Equity	Exhibit 1.4	c	9.71%	9.96%	-0.25%	-0.05%	-0.16%	-0.23%	9.30%	9.68%
Return on Equity		d = a x b x c	395.3	420.6	(10.2)	(2.2)	(6.5)	(9.7)	378.5	408.8
Regulatory Income Tax		e = l	71.8	82.8	(3.7)	(0.8)	(2.3)	(3.5)	65.7	78.6
Regulatory Net Income (before tax)		f = d + e	467.0	503.5	(13.9)	(2.9)	(8.9)	(13.2)	444.2	487.3
Timing Differences *(Note 1)*		g	(192.9)	(187.8)	-	-	-	-	(192.9)	(187.8)
Taxable Income		h = f + g	274.1	315.7	(13.9)	(2.9)	(8.9)	(13.2)	251.3	299.6
Tax Rate		i	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Income Tax		j = h x i	72.6	83.7	(3.7)	(0.8)	(2.3)	(3.5)	66.6	79.4
less: Income Tax Credits		k	(0.9)	(0.8)	-	-	-	-	(0.9)	(0.8)
Regulatory Income Tax		l = j + k	71.8	82.8	(3.7)	(0.8)	(2.3)	(3.5)	65.7	78.6

Note 1. Book to Tax Timing Differences	Hydro One Proposed 2015	Hydro One Proposed 2016	OEB Decision Impact 2015	OEB Decision Impact 2016	OEB Approved 2015	OEB Approved 2016
Depreciation	394.2	404.0	-	-	394.2	404.0
CCA	(509.3)	(512.5)	-	-	(509.3)	(512.5)
Other Timing Differences	(77.8)	(79.3)	-	-	(77.8)	(79.3)
Total Timing Differences	(192.9)	(187.8)	-	-	(192.9)	(187.8)

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

External Revenue

($ millions)	Supporting Reference	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
External Revenue	*See supporting details below*	28.4	28.8	3.4	3.4	-	-	31.8	32.2

External Revenue Details E1-2-1 Page 2	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
Secondary Land Use	14.3	14.5	3.4	3.4	-	-	17.7	17.9
Station Maintenance	7.2	7.3	-	-	-	-	7.2	7.3
Engineering & Construction	-	-	-	-	-	-	-	-
Other	6.9	7.0	-	-	-	-	6.9	7.0
Total	28.4	28.8	3.4	3.4	-	-	31.8	32.2

Note 1: As per Hydro One's Settlement Agreement approved by the Board on December 2, 2014, External Revenue is increased by $3.4M in 2015 and $3.4M in 2016.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Export Transmission Service Revenue

($ millions)	Supporting Reference	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
Export Transmission Service Revenue	see Note 1	(33.4)	(34.3)	2.5	2.6	-	-	(30.9)	(31.7)

Note 1: As per Hydro One's Settlement Agreement approved by the Board on December 2, 2014, the Export Transmission Service Revenue has been reduced to reflect a change in the ETS rate from $2.0 per MWh to $1.85 per MWh.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Deferral and Variance Accounts

($ millions)	**Supporting Reference**	**Hydro One Proposed 2015**	**Hydro One Proposed 2016**	**Settlement Impact 2015**	**Settlement Impact 2016**	**Cost of Capital Update 2015**	**Cost of Capital Update 2016**	**OEB Approved 2015**	**OEB Approved 2016**
Deferral and Variance Accounts	*See supporting details below*	(18.0)	(18.0)	18.0	(18.0)	0.0	0.0	0.0	(36.1)

Deferral and Variance Accounts Details F1-1-3	Hydro One Proposed 2015	Hydro One Proposed 2016	Settlement Impact 2015	Settlement Impact 2016	Cost of Capital Update 2015	Cost of Capital Update 2016	OEB Approved 2015	OEB Approved 2016
Excess Export Service Revenue	(11.8)	(11.8)	11.8	(11.8)	-	-	-	(23.5)
External Secondary Land Use Revenue	(9.3)	(9.3)	9.3	(9.3)	-	-	-	(18.5)
External Station Maintenance, E&CS Revenue and Other External Rever	(0.7)	(0.7)	0.7	(0.7)	-	-	-	(1.3)
Tax Rate Changes	0.4	0.4	(0.4)	0.4	-	-	-	0.8
Rights Payments	(1.0)	(1.0)	1.0	(1.0)	-	-	-	(1.9)
Pension Cost Differential	4.1	4.1	(4.1)	4.1	-	-	-	8.2
Long-Term Project Development	0.1	0.1	(0.1)	0.1	-	-	-	0.1
Total	(18.0)	(18.0)	18.0	(18.0)	0.0	0.0	-	(36.1)

Note 1: As per Hydro One's Settlement Agreement approved by the Board on December 2, 2014, the refund of Regulatory Accounts in the amount of $18.0M in 2015 is postponed to 2016 to smooth the rate impact.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Revenue Requirement Summary Excluding B2M LP

($ millions)	**Supporting Reference**	**OEB Approved 2015**	**OEB Approved 2016**	**B2M LP Impact 2015**	**B2M LP Impact 2016**	**OEB Approved Excluding B2M LP 2015**	**OEB Approved Excluding B2M LP 2016**
OM&A	Exhibit 1.1	432.0	437.4	(0.9)	(0.7)	431.1	436.7
Depreciation	Exhibit 1.2	394.2	404.0	(6.8)	(6.8)	387.4	397.3
Return on Debt	Exhibit 1.4	297.4	316.0	(15.1)	(15.2)	282.3	300.7
Return on Equity	Exhibit 1.4	378.5	408.8	(19.5)	(20.0)	359.0	388.8
Income Tax	Exhibit 1.5	65.7	78.6	1.6	0.6	67.4	79.1
Base Revenue Requirement		**1,567.8**	**1,644.8**	**(40.6)**	**(42.2)**	**1,527.2**	**1,602.6**
Deduct: External Revenue	Exhibit 1.6	(31.8)	(32.2)	-	-	(31.8)	(32.2)
Subtotal		**1,536.0**	**1,612.6**	**(40.6)**	**(42.2)**	**1,495.4**	**1,570.4**
Deduct: Export Tx Service Revenue	Exhibit 1.7	(30.9)	(31.7)	-	-	(30.9)	(31.7)
Deduct: Other Cost Charges	Exhibit 1.8	0.0	(36.1)	-	-	0.0	(36.1)
Add: Low Voltage Switch Gear	Note 1	12.8	13.3	-	-	12.8	13.3
Rates Revenue Requirement		**1,517.9**	**1,558.1**	**(40.6)**	**(42.2)**	**1,477.3**	**1,515.9**

Note 1: The value of $13.3M for LVSG in 2016 is an estimate and will be revised once the 2016 Revenue Requirement is finalized in the fall of 2015.
Note 2: B2M LP information is as per Exhibit A - Revised filed in EB-2014-0330 dated December 4, 2014.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Rate Base Excluding B2M LP

($ millions)	**Supporting Reference**	**OEB Approved 2015**	**OEB Approved 2016**	**B2M LP Impact 2015**	**B2M LP Impact 2016**	**OEB Approved Excluding B2M LP 2015**	**OEB Approved Excluding B2M LP 2016**
Rate Base	*See supporting details below*	10,175.3	10,556.9	(524.0)	(516.9)	9,651.3	10,040.0

<u>Rate Base Details</u>

	2015	2016
Utility plant (average)		
Gross plant at cost	547.8	547.8
Less: Accumulated depreciation	(24.8)	(31.6)
Add: CWIP	-	-
Net utility plant	523.0	516.2
Working capital		
Cash working capital	0.9	0.7
Materials & supplies inventory	-	-
Total working capital	0.9	0.7
Total Rate Base	524.0	516.9

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2014-0140

2015 Revenue Requirement by Rate Pool Prior to Excluding B2M LP

	Supporting Exhibit	**2015 Rate Pool Revenue Requirement ($ Million)**					
		Network	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.1*	222.7	43.3	99.6	365.5	0.2	365.7
Other Taxes (Grants-in-Lieu)	*Note 1*	41.8	9.2	15.3	66.3	0.0	66.3
Depreciation of Fixed Assets	*1.2*	213.3	43.9	98.8	356.0	0.0	356.0
Capitalized Depreciation	*Note 2*	(4.0)	(0.9)	(1.5)	(6.4)	0.0	(6.4)
Asset Removal Costs	*Note 2*	23.8	5.2	9.1	38.1	0.0	38.1
Other Amortization	*Note 2*	4.1	0.9	1.5	6.5	0.0	6.5
Return on Debt	*1.4*	187.5	41.2	68.6	297.3	0.0	297.4
Return on Equity	*1.4*	238.6	52.5	87.4	378.5	0.0	378.5
Income Tax	*1.5*	41.4	9.1	15.2	65.7	0.0	65.7
Base Revenue Requirement		**969.1**	**204.4**	**394.0**	**1567.5**	**0.3**	**1567.8**
Less Regulatory Asset Credit	*1.8*	0.0	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement		**969.1**	**204.4**	**394.0**	**1567.5**	**0.3**	**1567.8**
Less Non-Rate Revenues	*1.6*	(19.7)	(4.1)	(8.0)	(31.8)	0.0	(31.8)
Less Export Revenues	*1.7*	(30.9)			(30.9)		(30.9)
Plus LVSG Credit	*8.0*			12.8	12.8		12.8
Total Revenue Requirement for UTR		**918.6**	**200.2**	**398.8**	**1517.6**	**0.3**	**1517.9**

Note 1: Included in OEB Approved 2015 OMA total in Exhibit 1.1.
Note 2: Included in OEB Approved 2015 Depreciation total in Exhibit 1.2.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2014-0140

2015 Revenue Requirement by Rate Pool Excluding B2M LP

	Supporting Exhibit	2015 Rate Pool Revenue Requirement Excluding B2M LP ($ Million)					
		Network (Note 3)	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.1*	221.8	43.3	99.6	364.7	0.2	364.8
Other Taxes (Grants-in-Lieu)	*Note 1*	41.8	9.2	15.3	66.3	0.0	66.3
Depreciation of Fixed Assets	*1.2*	206.5	43.9	98.8	349.2	0.0	349.2
Capitalized Depreciation	*Note 2*	(4.0)	(0.9)	(1.5)	(6.4)	0.0	(6.4)
Asset Removal Costs	*Note 2*	23.8	5.2	9.1	38.1	0.0	38.1
Other Amortization	*Note 2*	4.1	0.9	1.5	6.5	0.0	6.5
Return on Debt	*1.4*	172.4	41.2	68.6	282.3	0.0	282.3
Return on Equity	*1.4*	219.1	52.5	87.4	359.0	0.0	359.0
Income Tax	*1.5*	43.1	9.1	15.2	67.4	0.0	67.4
Base Revenue Requirement		**928.6**	**204.4**	**394.0**	**1526.9**	**0.3**	**1527.2**
Less Regulatory Asset Credit	*1.8*	0.0	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement		**928.6**	**204.4**	**394.0**	**1526.9**	**0.3**	**1527.2**
Less Non-Rate Revenues	*1.6*	(19.7)	(4.1)	(8.0)	(31.8)	0.0	(31.8)
Less Export Revenues	*1.7*	(30.9)			(30.9)		(30.9)
Plus LVSG Credit	*8.0*			12.8	12.8		12.8
Total Revenue Requirement for UTR		**878.0**	**200.2**	**398.8**	**1477.0**	**0.3**	**1477.3**

Note 1: Included in OEB Approved 2015 OMA total in Exhibit 1.1.
Note 2: Included in OEB Approved 2015 Depreciation total in Exhibit 1.2.
Note 3: The revenue requirement allocated to the Network rate pool excludes the B2MLP 2015 interim revenue requirement show in Exhibit 2.0

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Summary Charge Determinants
(for Setting Uniform Transmission Rates for January 1, 2015 to December 31, 2015)

	2015 Total MW (Note 1)
Network	246,888
Line Connection	238,332
Transformation Connection	204,816

Note 1: 2015 charge determinant per Settlement Agreement Section II, Appendix C, Page 2 of 3.
Note 2: There is no customer load directly connected to the B2M LP system, therefore exclusion of B2M LP assets do not impact HONI charge determinants.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2015 to December 31, 2015)

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,761,177	$857,719	$1,708,192	$6,327,089
CNPI	$2,741,895	$625,277	$1,245,271	$4,612,443
GLPT	$22,578,930	$5,149,023	$10,254,543	$37,982,496
H1N	$878,027,045	$200,230,084	$398,768,505	$1,477,025,634
B2MLP	$40,550,724	$0	$0	$40,550,724
All Transmitters	$947,659,772	$206,862,103	$411,976,511	$1,566,498,386

Transmitter	Total Annual Charge Determinants (MW)			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	187.120	213.460	76.190	
CNPI	583.420	668.600	668.600	
GLPT	3,445.341	2,461.434	455.652	
H1N	246,888.000	238,332.000	204,816.000	
B2MLP	0.000	0.000	0.000	
All Transmitters	251,103.881	241,675.494	206,016.442	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.77**	**0.86**	**2.00**	
FNEI Allocation Factor	**0.00397**	**0.00415**	**0.00415**	
CNPI Allocation Factor	**0.00289**	**0.00302**	**0.00302**	
GLPT Allocation Factor	**0.02383**	**0.02489**	**0.02489**	
H1N Allocation Factor	**0.92652**	**0.96794**	**0.96794**	
B2MLP Allocation Factor	**0.04279**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.

Note 3: Rates Revenue Requirement and Charge Determinants per Board Decision on Settlement Agreement for EB-2012-0300 dated November 1, 2012 and the EB-2012-0310 2014 Transmission Revenue Requirement Decision and Order, December 19, 2013.

Note 4: H1N Rates Revenue Requirement per Board Decision on Settlement Agreement for EB-2014-0140 dated December 4, 2014.

Note 5: B2MLP Interim 2015 Revenue Requirement per Exhibit A - Revised in EB-2014-0330 dated December 4, 2014.

Note 6: Calculated data in shaded cells.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Revenue Requirement and Charge Determinant Assumptions for Other Transmitters

Table 1
Approved Annual Revenue Requirement and Charge Determinants

Transmitter	Annual Revenue Requirement ($)	Annual Charge Determinants (MW)			Approval Reference
		Network	Line Connection	Transformation Connection	
Five Nations Energy Inc. (FNEI)	$6,327,089	187.120	213.460	76.190	*Note 1*
Canadian Niagara Power Inc. (CNPI)	$4,612,443	583.420	668.600	668.600	*Note 2*
Great Lakes Power Transmission (GLPT)	$37,982,496	3,445.341	2,461.434	455.652	*Note 3*
Bruce to Milton Limited Partnership (B2M LP)	$40,550,724	-	-	-	*Note 4*

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010 and confirmed per email from Board Staff (H. Thiessen).

Note 2: Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001 and confirmed per email from Board Staff (H. Thiessen).

Note 3: Rates Revenue Requirement and Charge Determinants per Board Decision on Settlement Agreement for EB-2012-0300 dated November 1, 2012 and the EB-2012-0310 2014 Transmission Revenue Requirement Decision and Order, December 19, 2013.

Note 4: Interim 2015 Revenue Requirement per Exhibit A - Revised in EB-2014-0330 dated December 4, 2014. There is no customer load directly connected to the B2M LP system.

2015 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2014-0357

The rate schedules contained herein shall be effective January 1, 2015

Issued: To be determined
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 that 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 the 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 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. 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.

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): $ Per kW of Network Billing Demand[1,2]	**3.77**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.86**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**2.00**

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 embedded generation 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. 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.

HYDRO ONE NETWORKS INC.
Ontario, Canada

WHOLESALE METER SERVICE
And
EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: To be determined
Ontario Energy Board

RATE SCHEDULE: HON-MET	HYDRO ONE NETWORKS - WHOLESALE METER SERVICE

APPLICABILITY:

This rate 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) 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 rate 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.

The Wholesale Meter Service rate covered by this schedule shall remain in place until such time as the rate is revised by Order of the Ontario Energy Board.

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*.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2014-0140

Wholesale Meter Rate Calculations

	Charge Determinant (Avg # of Meter Points)	Revenue Requirement ($ Million)	OEB Approved Rate * ($/Meter Point/Year)	Hydro One Proposed Rate * ($/Meter Point/Year) (Note 1)
	Note 1	*Note 2*		
	(A)	(B)	(B) / (A)	
2015	35	0.3	7,900	7,900
2016	25	0.2	7,900	7,900
Average 2015 & 2016			7,900	7,900

* Rate is rounded down to the nearest $100

Note 1: Per EB-2014-0140, Exhibit H1, Tab 4, Schedule 1, Table 1

Note 2: Per Exhibit 3.0

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2014-0140

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2015

Charge Determinant (MW)	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)**	**Rate Before LVSG Credit ($/kw/month)**	**Average Monthly NCP Demand for Toronto Hydro and Hydro Ottawa (MW)**	**LVS Proportion (%)**	**Final LSVG Credit ($M)**
(Note 1)	*(Note 2)*		*(Note 3)*	*(Note 4)*	
(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
204,816	386.0	1.884	2977	19.0%	12.8

Note 1: Per Exhibit 5.0

Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues allocated to Transformation Connection Pool, as per information in Exhibit 3.0.

Note 3: Per EB-2014-0140 Exhibit H1, Tab 3, Schedule 1.

Note 4: Per EB-2012-0031 Exhibit G1, Tab 4, Schedule 1, page 1.