Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0031

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order or orders approving a transmission revenue requirement and rates and other charges for the transmission of electricity for 2013 and 2014.

BEFORE: Paula Conboy
Presiding Member

Cynthia Chaplin
Vice Chair and Member

Emad Elsayed
Member

RATE ORDER
2014 UNIFORM ELECTRICITY TRANSMISSION RATES
January 09, 2014

Hydro One Networks Inc. ("Hydro One") filed an application, dated May 28, 2012, with the Ontario Energy Board (the "Board") under section 78 of the *Ontario Energy Board Act, 1998*, c.15, Schedule B, seeking approval for changes to its 2013 and 2014 transmission revenue requirement and for changes to the provincial uniform transmission rates charged for electricity transmission, to be effective January 1, 2013 and January 1, 2014. The Board assigned File Number EB-2012-0031 to the application.

The Board issued an oral decision on November 8, 2012 (the "November Decision") to accept a settlement proposal filed by Hydro One on November 6, 2012. On November 30, 2012, Hydro One filed its 2013 Draft Rate Order including a revised Transmission Connection Procedures document and Hydro One Networks' updated 2013 transmission revenue requirement reflecting the November Decision and the relevant information for the calculation of the 2013 uniform transmission rates.

On December 20, 2012, the Board issued its EB-2012-0031 Rate Order on the 2013 Uniform Transmission Rates, effective January 1, 2013. An outstanding issue from EB-2012-0031, regarding the export transmission rate, was resolved in a decision and order issued by the Board on June 6, 2013.

On December 6, 2013, Hydro One filed its 2014 Draft Rate Order including its 2014 transmission revenue requirement reflecting the November Decision and the relevant information for the calculation of the 2014 uniform transmission rates (UTR), including updates to the cost of capital consistent with the Board's letter issued on November 25, 2013, which set out the Cost of Capital Parameter Updates for Cost of Service applications with rates effective in 2014.

The Board notes that the Draft Rate Order implements the Board's November Decision for Hydro One and shows the resulting calculation of the UTR and revenue shares. The Draft Rate Order includes the most recent approved revenue requirements and pool load forecasts for each of the other Ontario transmitters: Great Lakes Power Transmission Inc., Canadian Niagara Power Inc. and Five Nations Energy Inc. as shown below:

- Great Lakes Power Transmission Inc. (EB-2012-0300) 2014 Revenue Requirement issued December 19, 2013;
- Five Nations Energy Inc. (EB-2009-0387) issued December 9, 2010; and,
- Canadian Niagara Power Inc. (EB-2001-0034) issued December 11, 2001.

The Board also notes that Ontario electricity transmitters were given the opportunity to submit comments on the Draft Rate Order. No comments were received.

Intervenors were also provided with an opportunity to provide comments on the 2014 UTR Draft Rate Order as filed by Hydro One and again, no comments were received.

The Board finds that Hydro One has reasonably and appropriately reflected the Board's November Decision in the 2014 Draft Rate Order. The Board also finds that Hydro One has appropriately reflected the relevant Board decisions regarding the other Ontario transmitters in the 2014 Draft Rate Order.

The Board finds it appropriate to issue a final Rate Order approving Hydro One's 2014 transmission revenue requirements and charge determinants for use in setting the 2014 Ontario Uniform Electricity Transmission rates.

THE BOARD ORDERS THAT:

1. The Hydro One Transmission Rates Revenue Requirement for 2014, $1,446.4 million as shown in Exhibit 1.0 in Appendix A, is approved for recovery through the Uniform Electricity Transmission Rates.

2. The allocation of the approved revenue requirements to the three electricity transmission rate pools as shown in Exhibit 2.0 in Appendix A is approved.

3. The Hydro One charge determinants for each rate pool as shown in Exhibit 3.0 in Appendix A are approved.

4. The final revenue requirements by rate pool and the uniform electricity transmission rates and revenue allocators for rates effective January 1, 2014 as shown in Exhibit 4.0 in Appendix A are approved.

5. The 2014 Ontario Uniform Transmission Rate Schedules, attached as Appendix B, are approved.

6. The Wholesale Meter Service and Exit Fee Schedule, attached as Exhibit 5.0 in Appendix B, is approved.

6. The Low Voltage Switchgear Credit, attached as Exhibit 6.0 in Appendix B, is approved.

ISSUED at Toronto, January 9, 2014

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

HYDRO ONE NETWORKS INC.

2014 RATE ORDER

EB-2012-0031

JANUARY 9, 2014

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031

Revenue Requirement Summary

($ millions)	Supporting Reference	Hydro One Proposed 2014	OEB Decision Impact 2014	OEB Approved 2014	Cost of Capital Update 2014	Revised OEB Approved 2014
OM&A	Exhibit 1.1	459.7	(10.0)	449.7	-	449.7
Depreciation	Exhibit 1.2	374.7	(3.3)	371.5	-	371.5
Return on Debt	Exhibit 1.4	288.5	(3.4)	285.1	2.7	287.9
Return on Equity	Exhibit 1.4	379.5	(10.8)	368.7	3.1	371.8
Income Tax	Exhibit 1.5	55.2	(1.8)	53.4	1.1	54.5
Base Revenue Requirement		**1,557.7**	**(29.3)**	**1,528.4**	**6.9**	**1,535.3**
Deduct: External Revenue	Exhibit 1.6	(31.8)	(4.8)	(36.6)	-	(36.6)
Subtotal		**1,525.9**	**(34.1)**	**1,491.8**	**6.9**	**1,498.7**
Deduct: Export Tx Service Revenue	Exhibit 1.7	(30.1)	(4.0)	(34.1)	-	(34.1)
Deduct: Other Cost Charges	Exhibit 1.8	(15.1)	(15.1)	(30.3)	-	(30.3)
Add: Low Voltage Switch Gear		12.5	(0.4)	12.1	-	12.1
Rates Revenue Requirement		**1,493.1**	**(53.6)**	**1,439.5**	**6.9**	**1,446.4**

Note 1: The 2014 Cost of Capital is updated to reflect OEB approved parameters issued on November 25, 2013, updated forecast of 2014 third-party long-term debt rate and 2013 actual debt issues.
Note 2: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, the refund of Regulatory Accounts in the amount of $15.1M in 2013 is postponed to 2014 to keep the overall rate increase at 0% in 2013.
Note 3: The Export Tx Service Revenue is reduced by $4M in 2013 but increased by $4M in 2014 to keep the overall rate increase at 0% in 2013.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031
As filed on November 30, 2012

OM&A

($ millions)	**Supporting Reference**	**Hydro One Proposed 2014**	**OEB Decision Impact 2014**	**OEB Approved 2014**	**Cost of Capital Update 2014**	**Revised OEB Approved 2014**
OM&A	*See supporting details below*	459.7	(10.0)	449.7	-	449.7

OEB Decision Impact Supporting Details

Adjustments	**Reference**	**2014 OM&A Impacts**
Settlement Agreement	Page 10	(10.0)
		(10.0)

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, OM&A expenses are reduced by $13M in 2013 and $10M in 2014 from Hydro One's application filed on August 28, 2012.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031
As filed on November 30, 2012

Rate Base and Depreciation

($ millions)	**Supporting Reference**	**Hydro One Proposed 2014**	**OEB Decision Impact 2014**	**OEB Approved 2014**	**Cost of Capital Update 2014**	**Revised OEB Approved 2014**
Rate Base	*See supporting details below*	10,050.9	(117.3)	9,933.8	-	9,933.8
Depreciation	*See supporting details below*	374.7	(3.3)	371.5	-	371.5

OEB Decision Impact Supporting Details	**Reference**	**2014 Detailed Computation**	**2014 Rate Base Impact**	**2014 Depreciation Impact**
Working Capital Adjustment				
Rate Base Details	Pre-filed Evidence Exh D1-1-1			
Utility plant (average)				
Gross plant at cost		15,293.7		
Less: Accumulated depreciation		(5,267.4)		
Add: CWIP		-		
Net utility plant		10,026.4		
Working capital				
Cash working capital		11.7		
Materials & supplies inventory		12.9		
Total working capital		24.6		
Total Rate Base		10,050.9		
Working capital as % of OM&A	(a)	5.3%		
OM&A Reduction per Settlement Agreement	Exhibit 1.1 (b)	(10.0)		
Working capital reduction	(c) = (a) x (b)	(0.5)	(0.5)	
		2014 Capex		
Capex Adjustments				
Settlement Agreement	Page 14	-	(116.7)	(3.3)
Total		-	(117.3)	(3.3)

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, Capital Expreditures are reduced by $120M in 2013 from Hydro One's application filed on August 28, 2012.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031
As filed on November 30, 2012

Capital Expenditures

($ millions)	**Supporting Reference**	**Hydro One Proposed 2014**	**OEB Decision Impact 2014**	**OEB Approved 2014**	**Cost of Capital Update 2014**	**Revised OEB Approved 2014**
Capital expenditures	*See supporting details below*	1,121.5	-	1,121.5	-	1,121.5

OEB Decision Impact Supporting Details		**2014 Capex Impacts**
Settlement Agreement	Page 14	-
		-

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, no adjustments to 2014 Capital Expreditures from Hydro One's application filed on August 28, 2012.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031

Capital Structure and Return on Capital

($ millions)	Supporting Reference	Hydro One Proposed 2014	OEB Decision Impact 2014	OEB Approved 2014	Cost of Capital Update 2014	Revised OEB Approved 2014
Return on Rate Base					Note 2	Note 2
Rate Base	Exhibit 1.2	$ 10,050.9	$ (117.3)	$ 9,933.8	$ -	$ 9,933.8
Capital Structure:						
Third-Party long-term debt		58.6%	(1.9%)	56.7%	-2.8%	53.9%
Deemed long-term debt		-2.6%	1.9%	-0.7%	2.8%	2.1%
Short-term debt		4.0%	0.0%	4.0%	0.0%	4.0%
Common equity		40.0%	0.0%	40.0%	0.0%	40.0%
Capital Structure:						
Third-Party long-term debt	Exhibit 1.4.1	5,890.8	(258.4)	5,632.4	(275.0)	5,357.4
Deemed long-term debt		(262.2)	192.8	(69.5)	275.0	205.5
Short-term debt		402.0	(4.7)	397.4	-	397.4
Common equity		4,020.4	(46.9)	3,973.5	-	3,973.5
		10,050.9	**$ (117.3)**	**9,933.8**	**-**	**9,933.8**
Allowed Return:						
Third-Party long-term debt	Exhibit 1.4.1	4.83%	(0.00%)	4.83%	0.11%	4.94%
Deemed long-term debt	Exhibit 1.4.1	4.83%	(0.00%)	4.83%	0.11%	4.94%
Short-term debt	Note 1	2.98%	0.00%	2.98%	-0.87%	2.11%
Common equity	Note 1	9.44%	(0.16%)	9.28%	0.08%	9.36%
Return on Capital:						
Third-Party long-term debt		284.4	(12.6)	271.9	(7.4)	264.4
Deemed long-term debt		(12.7)	9.3	(3.4)	13.5	10.1
Short-term debt		12.0	(0.1)	11.8	(3.5)	8.4
AFUDC return on Niagara Reinforcement Project	see below	4.8	(0.0)	4.8	0.1	4.9
Total return on debt		**$ 288.5**	**$ (3.4)**	**$ 285.1**	**$ 2.7**	**$ 287.9**
Common equity		**$ 379.5**	**$ (10.8)**	**$ 368.7**	**$ 3.1**	**$ 371.8**
AFUDC return on Niagara Reinforcement Project						
CWIP		99.1		99.1	-	99.1
Deemed long-term debt		4.83%		4.83%	0.11%	4.94%
		4.8		4.8	0.1	4.9

Note 1: The approved rates follow the OEB's November 15, 2012 guidance on cost of capital parameters to reflect the September 2012 Consensus Forecast.
Note 2: The 2014 Cost of Capital is updated to reflect OEB approved parameters issued on November 25, 2013, updated forecast of 2014 third-party long-term debt rate and 2013 actual debt issues.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2014)
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/13 ($Millions)	Total Amount Outstanding: at 12/31/14 ($Millions)	Avg. Monthly Averages ($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	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	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	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	0.0	148.1	4.8	
20	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	
21	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	
22	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
23	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	
24	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
25	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
26	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	154.0	154.0	154.0	5.0	
27	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.99	3.08%	165.0	165.0	165.0	5.1	
28	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.52	4.02%	68.8	68.8	68.8	2.8	
29	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.52	3.81%	52.5	52.5	52.5	2.0	
30	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.21	3.83%	141.0	141.0	141.0	5.4	
31	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	Note 1
32	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	Note 1
33	15-Mar-14	4.928%	15-Mar-44	289.8	1.4	288.4	99.50	4.96%	0.0	289.8	223.0	11.1	Note 2
34	15-Jun-14	4.091%	15-Jun-24	289.8	1.4	288.4	99.50	4.15%	0.0	289.8	156.1	6.5	Note 2
35	15-Sep-14	3.101%	15-Sep-19	289.8	1.4	288.4	99.50	3.21%	0.0	289.8	89.2	2.9	Note 2
37		**Subtotal**							4916.1	5610.6	5357.4	259.5	
38		Treasury OM&A costs										1.7	
39		Other financing-related fees										3.3	
40		**Total**							4916.1	5610.6	5357.4	264.4	4.94%

Note 1: Updated to reflect actual 2013 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2014 as per the October 2013 long-term Consensus Forecast

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2012-0031

Income Tax

($ millions)	Supporting Reference	Hydro One Proposed 2014	OEB Decision Impact 2014	OEB Approved 2014	Cost of Capital Update 2014	Revised OEB Approved 2014
Income Taxes	*See supporting details below*	55.2	(1.8)	53.4	1.1	54.5

Income Tax Supporting Details			Hydro One Proposed 2014	OEB Decision Impact 2014	OEB Approved 2014	Cost of Capital Update 2014	Revised OEB Approved 2014
Rate Base	Exhibit 1.2	a	$ 10,050.9	$ (117.3)	$ 9,933.8	$ -	$ 9,933.8
Common Equity Capital Structure		b	40.0%		40.0%		40.0%
Return on Equity	Exhibit 1.4	c	9.44%	-0.16%	9.28%	0.08%	9.36%
Return on Equity		d = a x b x c	379.5	(10.8)	368.7	3.1	371.8
Regulatory Income Tax		e = l	55.2	(1.8)	53.4	1.1	54.5
Regulatory Net Income (before tax)		f = d + e	434.8	(12.6)	422.2	4.2	426.3
Timing Differences *(Note 1)*		g	(215.4)	9.6	(205.8)	-	(205.8)
Taxable Income		h = f + g	219.4	(3.0)	216.4	4.2	220.5
Tax Rate		i	26.5%		26.5%		26.5%
Income Tax		j = h x i	58.1	(0.8)	57.3	1.1	58.4
less: Income Tax Credits		k	(2.9)	(1.0)	(3.9)	-	(3.9)
Regulatory Income Tax		l = j + k	55.2	(1.8)	53.4	1.1	54.5

Note 1. Book to Tax Timing Differences	Hydro One Proposed 2014	OEB Decision Impact 2014	OEB Approved 2014	Cost of Capital Update 2014	Revised OEB Approved 2014
Depreciation	374.7	(3.3)	371.5	-	371.5
CCA	(523.2)	11.8	(511.4)	-	(511.4)
Other Timing Differences	(66.9)	1.0	(65.9)	-	(65.9)
Total Timing Differences	(215.4)	9.6	(205.8)	-	(205.8)

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, the Apprenticeship Tax Credit is increased by $1M in 2014.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031
As filed on November 30, 2012

External Revenue

($ millions)	**Supporting Reference**	**Hydro One Proposed 2014**	**OEB Decision Impact 2014**	**OEB Approved 2014**	**Cost of Capital Update 2014**	**Revised OEB Approved 2014**
External Revenue	*See supporting details below*	31.8	4.8	36.6	-	36.6

External Revenue Details E1-2-1 Page 2	Hydro One Proposed 2014	OEB Decision Impact 2014	OEB Approved 2014	Cost of Capital Update 2014	Revised OEB Approved 2014
Secondary Land Use	13.2	-	13.2	-	13.2
Station Maintenance	8.1	-	8.1	-	8.1
Engineering & Construction	3.0	-	3.0	-	3.0
Other	7.5	4.8	12.3	-	12.3
Total	31.8	4.8	36.6	-	36.6

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, External Revenue is increased by $4.8M in 2014.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031
As filed on November 30, 2012

Export Transmission Service Revenue

($ millions)	**Supporting Reference**	**Hydro One Proposed 2014**	**OEB Decision Impact 2014**	**OEB Approved 2014**	**Cost of Capital Update 2014**	**Revised OEB Approved 2014**
Export Transmission Service Revenue	see below	(30.1)	(4.0)	(34.1)	-	(34.1)

	OEB Decision Impact 2014
Settlement Adjustment (note 1)	(4.0)

Note 1: Export Tx Service Revenue is reduced by $4M in 2013 but increased by $4M in 2014 to maintain 0% rate increase in 2013.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031
As filed on November 30, 2012

Deferral and Variance Accounts

($ millions)	**Supporting Reference**	**Hydro One Proposed 2014**	**OEB Decision Impact 2014**	**OEB Approved 2014**	**Cost of Capital Update 2014**	**Revised OEB Approved 2014**
Deferral and Variance Accounts	*See supporting details below*	(15.1)	(15.1)	(30.3)	-	(30.3)

Deferral and Variance Accounts Details F1-1-3	Hydro One Proposed 2014	OEB Decision Impact 2014	OEB Approved 2014	Cost of Capital Update 2014	Revised OEB Approved 2014
Deferred Export Service Credit	(1.5)	(1.5)	(2.9)		(2.9)
Excess Export Service Revenue	(9.5)	(9.5)	(19.0)		(19.0)
External Secondary Land Use Revenue	(7.3)	(7.3)	(14.6)		(14.6)
External Station Maintenance and E&CS Revenue	(2.6)	(2.6)	(5.2)		(5.2)
Tax Rate Changes	(2.2)	(2.2)	(4.3)		(4.3)
Rights Payments	(0.9)	(0.9)	(1.8)		(1.8)
Long-Term Project Development	2.4	2.4	4.7		4.7
Pension Cost Differential	6.4	6.4	12.8		12.8
Total	(15.1)	(15.1)	(30.3)	-	(30.3)

Note 1: Regulatory Account balance refund is reduced by $15.1M in 2013 but increased by $15.1M in 2014 to maintain 0% rate increase in 2013.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031

Continuity of Revenue Requirement

	Submission 2014	OEB Decision 2014	Cost of Capital 2014	Final 2014
Revenue Requirement				
OM&A	459.7	(10.0)	0.0	449.7
Depreciation	374.7	(3.3)	0.0	371.5
Return on debt	288.5	(3.4)	2.7	287.9
Return on common equity	379.5	(10.8)	3.1	371.8
Income tax	55.2	(1.8)	1.1	54.5
	1557.7	(29.3)	6.9	1535.3
Rate Base	10050.9	(117.2)	0.0	9933.8
Capex	1121.5	0.0	0.0	1121.5

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2012-0031

2014 Revenue Requirement by Rate Pool

	Supporting Exhibit	2014 Rate Pool Revenue Requirement ($ Million)					
		Network	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.1*	234.9	39.7	102.3	376.9	0.4	377.4
Other Taxes (Grants-in-Lieu)	*Note 1*	45.6	9.8	16.9	72.3	0.0	72.3
Depreciation of Fixed Assets	*1.2*	203.6	39.5	89.4	332.5	0.1	332.5
Capitalized Depreciation	*Note 2*	(6.2)	(1.3)	(2.3)	(9.8)	0.0	(9.8)
Asset Removal Costs	*Note 2*	26.2	5.7	10.0	41.9	0.0	41.9
Other Amortization	*Note 2*	4.3	0.9	1.6	6.8	0.0	6.9
Return on Debt	*1.4*	181.5	39.2	67.1	287.8	0.1	287.9
Return on Equity	*1.4*	234.4	50.6	86.7	371.7	0.1	371.8
Income Tax	*1.5*	34.4	7.4	12.7	54.5	0.0	54.5
Base Revenue Requirement		**958.8**	**191.5**	**384.3**	**1534.6**	**0.7**	**1535.3**
Less Regulatory Asset Credit	*1.8*	(18.9)	(3.8)	(7.6)	(30.3)	0.0	(30.3)
Total Revenue Requirement		**939.8**	**187.7**	**376.8**	**1504.3**	**0.7**	**1505.0**
Less Non-Rate Revenues	*1.6*	(22.9)	(4.6)	(9.2)	(36.6)	0.0	(36.6)
Less Export Revenues	*1.7*	(34.1)			(34.1)		(34.1)
Plus LVSG Credit	*6.0*			12.1	12.1		12.1
Total Revenue Requirement for UTR		**882.9**	**183.2**	**379.7**	**1445.8**	**0.7**	**1446.4**

Note 1: Included with OM&A total in Exhibit 1.1. See EB-2012-0031 Exhibit G2, Tab 5, Schedule 1, Page 1.
Note 2: Included with Depreciation total in Exhibit 1.2. See EB-2012-0031 Exhibit G2, Tab 5, Schedule 1, Page 1.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2012-0031

Summary Charge Determinants
(for Setting Uniform Transmission Rates for January 1, 2014 to December 31, 2014)

	2014 Total MW *
Network	234,635
Line Connection	227,881
Transformation Connection	196,795

* *2014 charge determinants per Exhibit H1, Tab 3, Schedule 1, Table 1, multiplied by 12.*

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2012-0031

Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2014 to December 31, 2014)

Transmitter	**Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,863,796	$801,616	$1,661,678	$6,327,089
CNPI	$2,816,704	$584,377	$1,211,362	$4,612,443
GLPT	$23,194,963.65	$4,812,222	$9,975,310	$37,982,496
H1N	$882,891,274.05	$183,172,052	$379,699,417	$1,445,762,743
All Transmitters	$912,766,737	$189,370,267	$392,547,767	$1,494,684,771

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	234,635.292	227,880.899	196,795.322	
All Transmitters	238,851.173	231,224.393	197,995.764	

Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.82**	**0.82**	**1.98**	
FNEI Allocation Factor	**0.00423**	**0.00423**	**0.00423**	
CNPI Allocation Factor	**0.00309**	**0.00309**	**0.00309**	
GLPT Allocation Factor	**0.02541**	**0.02541**	**0.02541**	
H1N Allocation Factor	**0.96727**	**0.96727**	**0.96727**	
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-2012-0300 2014 Transmission Revenue Requirement Decision and Order, December 19, 2013.

Note 4: H1N Revenue Requirement per Exhibit E, Tab 1, Schedule 1 and Charge Determinants per Exhibit H1, Tab 3, Schedule 1, Table 1 under proceeding EB-2012-0031.

Note 5: Calculated data in shaded cells.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031

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*

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-2012-0300 2014 Transmission Revenue Requirement Decision and Order, December 19, 2013.

APPENDIX B

HYDRO ONE NETWORKS INC.

2014 RATE ORDER

EB-2012-0031

JANUARY 9, 2014

2014 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2012-0031

The rate schedules contained herein shall be effective January 1, 2014.

Issued: January 9, 2014
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, or has fully contributed toward the costs of, 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, or has fully contributed toward the costs of, 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]	**3.82**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.82**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**1.98**

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):	$2.00 / 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

As filed on November 30, 2012

Rate Schedule: HON-MET
Issued: January 9, 2014
Ontario Energy Board

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-2012-0031
As filed on November 30, 2012

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)	
2013	118	0.9	8,000	7,900
2014	87	0.7	7,800	7,900
Average 2013 & 2014			7,900	7,900

* Rate is rounded down to the nearest $100

Note 1: Per EB-2012-0031, Exhibit H1, Tab 4, Schedule 1, Table 1.
Note 2: Per Exhibit 2.0

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2014

Charge Determinant (MW) *(Note 1)*	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)** *(Note 2)*	**Rate Before LVSG Credit ($/kw/month)**	**Average Monthly NCP Demand for Toronto Hydro and Hydro Ottawa (MW)** *(Note 3)*	**LVS Proportion (%)** *(Note 4)*	**Final LSVG Credit ($M)**
(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
196,795	367.6	1.868	2843	19.0%	12.1

Note 1: Per Exhibit 3.0

Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues allocated to Transformation Connection Pool, as per information in Exhibit 2.0.

Note 3: Per EB-2012-0031 Exhibit G1, Tab 4, Schedule 1, Table 1

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