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Susan Frank
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BY COURIER

December 1, 2011

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

Dear Ms. Walli

EB-2011-0268 – Adjustment to Hydro One Networks' 2012 Electricity Transmission Revenue Requirement To Reflect Adoption of US GAAP – Final 2012 Revenue Requirement & Charge Determinants in Accordance with Decision

In its Decision with Reasons dated November 23, 2011 granting approval of Hydro One's request to utilize US GAAP for regulatory accounting, reporting and rate setting purposes, the Board directed Hydro One to file with the Board and all intervenors of record:

- A draft exhibit showing the final revenue requirement to reflect the Board's findings in this Decision, and
- An exhibit showing the calculation of the uniform transmission rates and revenue shares resulting from this Decision.

Attached please find the requested exhibits, as well as documentation providing a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits, as specified by the Board. The base revenue requirement of $1418.4 million for 2012 is detailed in Exhibits 1.0 to 1.9. The calculation of the 2012 UTR's, wholesale meter rates, low voltage switchgear credit, charge determinants and revenue shares resulting from the Board's findings in this decision are detailed in exhibits 2.0 to 6.0. The 2012 UTR's in $/kW-Month are determined to be 3.57 for Network, 0.80 for Line Connection and 1.86 for Transformation Connection. Please be aware that the UTR calculations have applied proposed 2012 figures for GLPT as the final Board approved levels are not yet available. Hydro One will provide the Board with adjusted UTR's if there is any change in the approved GLPT levels when they become available.

In addition, a listing of the studies and reports requested by the Board in their Decision (as well as those in the prior EB-2010-0002 Decision) and a listing of all variance and deferral accounts as approved by the Board in their Decision (as well as those in the prior EB-2010-0002 Decision) are provided in exhibits 7 and 8 respectively.

The attached exhibits reflect all changes to 2012 as ordered by the Board to Hydro One's proposed submission as summarized in Hydro One's prefiled evidence. In summary, Hydro One has:

- Reflected the $200 million shift of OM&A to CAPEX due to the transition to US GAAP and the relevant capitalization policy. Rate base was also updated to reflect this change.
- Applied the cost of capital parameters released by the Board on November 10, 2011 for purposes of establishing Hydro One's cost of capital for 2012.
- Updated the average cost of embedded debt for 2012 by incorporating the actual principal amount and cost rate for debt issued in 2011, and the forecast coupon rates for 2012 consistent with the September 2011 long-term consensus forecast.
- Due to the reduced 2012 Revenue Requirement from the above changes, Hydro One has also lowered its Low Voltage Switchgear Credit. This is reflected in its 2012 Wholesale Meter Rate.

As directed by the Board, all intervenors, by copy of this letter, are notified of this filing with the Board and of the fact that they have the opportunity to provide comment, if any, to the Board within 7 calendar days from today.

If you have any questions regarding this submission please contact Pasquale Catalano at 416 345-5405.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.
c. EB-2011-0268 Intervenors (electronic)

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2012 REVENUE REQUIREMENT, CHARGE DETERMINANTS & OTHER

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Revenue Requirement Summary

($ millions)	**Supporting Reference**	**Hydro One Proposed 2012**	**OEB Decision Impact 2012**	**OEB Approved 2012**	**US GAAP Impact 2012**	**Cost of Capital Update 2012**	**Revised OEB Approved 2012**
				Note 3	Note 4	Note 5	
OM&A	Exhibit 1.1	450.0	177.1	627.1	(200.0)	-	427.1
Depreciation	Exhibit 1.2	334.8	(4.1)	330.8	2.0	-	332.8
Return on Debt	Exhibit 1.4	312.3	(25.1)	287.1	1.6	(12.3)	276.4
Return on Equity	Exhibit 1.4	380.4	(28.3)	352.1	1.9	(23.4)	330.6
Income Tax	Exhibit 1.5	70.0	(9.4)	60.6	(0.8)	(8.3)	51.5
Base Revenue Requirement		**1,547.4**	**110.2**	**1,657.6**	**(195.3)**	**(43.9)**	**1,418.4**
Deduct: External Revenue	Exhibit 1.6	24.7	4.0	28.7	-	-	28.7
Subtotal		**1,522.7**	**106.2**	**1,628.9**	**(195.3)**	**(43.9)**	**1,389.7**
Deduct: Export Tx Service Revenue	Exhibit 1.7	(10.2)	(5.8)	(16.0)	-	-	(16.0)
Deduct: Other Cost Charges	Exhibit 1.8	2.6	(2.6)	-	-	-	-
Add: Low Voltage Switch Gear	Note 2	12.5	1.4	13.9	-	(2.4)	11.5
Rates Revenue Requirement		**1,527.5**	**99.3**	**1,626.8**	**(195.3)**	**(46.3)**	**1,385.1**

Note 1: In 2011, a variance account was established for property rights payments to track changes from approved amounts. Further, the 2012 Revenue Requirement impact if the Bruce to Milton Project in-service date is delayed from 2012 until 2013 will also be tracked in a variance account. Also, variance accounts will continue to be utilized for export revenues, secondary land use, External Station Maintenance and E&CS revenues to track changes from approved amounts.
Note 2: The amount of LVSG in 2012 has been revised to reflect the change in 2012 Revenue Requirement due to US GAAP impact as per EB-2001-0268 Decision with Reasons on November 23, 2011 and Cost of Capital parameters update issued by the OEB on November 10, 2011.
Note 3: As per K. Walli Jan. 18, 2011 "Revenue Requirement and Charge Determinant Order Arising From The EB-2010-0002 Decision With Reaons of December 23, 2010 and 2011 Uniform Electricity Transmission Rate Order (Revised)", Appendix A; and as per S. Frank, Jan. 5, 2011 "EB-2010-0002 Hydro One Networks' 2011-2012 Electricity Transmission Revenue Requirement - Final Revenue Requirements & Charge Determinants in Accordance With Decision".
Note 4: As per EB-2011-0268 Decision, Page 12, issued on November 23, 2011, adjustments have been made to reflect the impact on Revenue Requirement upon the adoption of US GAAP.
Note 5: As per EB-2010-0002 and EB-2011-0268 Decisions, the 2012 Cost of Capital is updated to reflect OEB approved parameters issued on November 10, 2011, updated forecast 2012 third-party long-term debt rate and 2011 actual debt issua

**** Notes 3, 4 and 5 apply to Exhibit 1.1 to 1.9 inclusive

Hydro One Networks Inc.
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OM&A

($ millions)	**Supporting Reference**	**Hydro One Proposed 2012**	**OEB Decision Impact 2012**	**OEB Approved 2012**	**US GAAP Impact 2012**	**Cost of Capital Update 2012**	**Revised OEB Approved 2012**
OM&A	*See supporting details below*	450.0	177.1	627.1	(200.0)	-	427.1

OEB Decision Impact Supporting Details

Adjustments	**EB-2010-0002 Decision Reference**	**2012 OM&A Impacts**	**US GAAP Impact Adjustment**
Adjustment for HST	Page 11	(5.1)	
Envelope Reduction	Page 11	(17.8)	
IFRS Accounting for Overheads Capitalized	Page 62	200.0	(200.0)
		177.1	(200.0)

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Rate Base and Depreciation

($ millions)	**Supporting Reference**	**Hydro One Proposed 2012**	**OEB Decision Impact 2012**	**OEB Approved 2012**	**US GAAP Impact 2012**	**Cost of Capital Update 2012**	**Revised OEB Approved 2012**
Rate Base	*See supporting details below*	9,134.6	(408.3)	8,726.3	48.1	-	8,774.4
Depreciation	*See supporting details below*	334.8	(4.1)	330.8	2.0	-	332.8

OEB Decision Impact Supporting Details	**EB-2010-0002 Decision Reference**			**Detailed US GAAP Impact Computation**	
Working Capital Adjustment					
Rate Base Details	Pre-filed Evidence Exh				
Utility plant (average)	D1-1-1				
Gross plant at cost		13,509.5		13,509.5	
Less: Accumulated depreciation		(4,690.6)		(4,690.6)	
Add: CWIP		289.0		289.0	
Net utility plant		9,107.9		9,107.9	
Working capital					
Cash working capital		5.0		5.0	
Materials & supplies inventory		21.7		21.7	
Total working capital		26.7		26.7	
Total Rate Base		9,134.6		9,134.6	
Working capital as % of OM&A	(a)	5.9%		5.9%	
OM&A Reduction (net of adjustment for HST)	Exhibit 1.1 (b)	182.2		200.0	
Working capital reduction	(c) = (a) x (b)	10.8	10.8	11.9	(11.9)
Capex Adjustments					
Adjustment for HST (includes working capital)	Page 30		(53.3)		
Adjustment for AFUDC rate	Page 31		(10.3)		
D43 and D44 Adjustment	Page 43		(24.6)		
Bruce x Milton CWIP removal	Page 47		(289.0)		
Bruce x Milton AFUDC add back (Note 1)	Page 47		18.0		
IFRS Accounting for Overheads Capitalized	Page 62		(60.0)		60.0
Total			(408.3)		48.1

Note 1: The 2012 Rate Base Impact of the Bruce to Milton AFUDC add back is net of a $23.3 million in-service additions correction. This latter amount will be placed into service in 2013.

Depreciation Adjustments					
Adjustment for HST (includes working capital)	Page 30		(1.7)		
Adjustment for AFUDC rate	Page 31		(0.2)		
D43 and D44 Adjustment	Page 43		(0.5)		
Bruce x Milton CWIP removal	Page 47		-		
Bruce x Milton AFUDC add back (Note 1)	Page 47		0.4		
IFRS Accounting for Overheads Capitalized	Page 62		(2.0)		2.0
Total			(4.1)		2.0

Hydro One Networks Inc.
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Capital Expenditures

($ millions)	Supporting Reference	Hydro One Proposed 2012	OEB Decision Impact 2012	OEB Approved 2012	US GAAP Impact 2012	Cost of Capital Update 2012	Revised OEB Approved 2012
Capital expenditures	*See supporting details below*	1,008.3	(227.0)	781.3	200.0	-	981.3

OEB Decision Impact Supporting Details	EB-2010-0002 Decision Reference	Capex Adjustment	US GAAP Impact Adjustment
Adjustment for HST (includes working capital)	Page 30	(30.6)	
Adjustment for AFUDC rate	Page 31	(2.1)	
D43 and D44 Adjustment	Page 43	(29.8)	
Bruce x Milton AFUDC add back	Page 47	35.5	
IFRS Accounting for Overheads Capitalized	Page 62	(200.0)	200.0
		(227.0)	200.0

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Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**Hydro One Proposed 2012**	**OEB Decision Impact 2012**	**OEB Approved 2012**	**US GAAP Impact 2012**	**Cost of Capital Update 2012**	**Revised OEB Approved 2012**
Return on Rate Base				Note 3			
Rate Base	Exhibit 1.2	$ 9,134.6	$ (408.3)	$ 8,726.3	48.1	-	8,774.4
Capital Structure:							
Third-Party long-term debt		56.7%	3.8%	60.5%	-0.3%	-5.9%	54.2%
Deemed long-term debt		-0.7%	(3.8%)	-4.5%	0.3%	5.9%	1.8%
Short-term debt		4.0%	0.0%	4.0%	0.0%	0.0%	4.0%
Common equity		40.0%	0.0%	40.0%	0.0%	0.0%	40.0%
Capital Structure:							
Third-Party long-term debt	Exhibit 1.4.1	5,175.1	100.0	5,275.2	-	(520.0)	4,755.1
Deemed long-term debt		(59.8)	(328.7)	(388.5)	27.0	520.0	158.5
Short-term debt		365.4	(16.3)	349.1	1.9	-	351.0
Common equity		3,653.8	(163.3)	3,490.5	19.3	-	3,509.8
		9,134.6	**$ (408.3)**	**8,726.3**	**48.1**	**-**	**8,774.4**
Allowed Return:							
Third-Party long-term debt	Note 1, Exhibit 1.4.1	5.64%	(0.24%)	5.40%	0.00%	-0.03%	5.37%
Deemed long-term debt	Note 2	5.64%	(0.24%)	5.40%	0.00%	-0.03%	5.37%
Short-term debt	Note 3	5.00%	0.19%	5.19%	0.00%	-3.11%	2.08%
Common equity	Note 3	10.41%	(0.32%)	10.09%	0.00%	-0.67%	9.42%
Return on Capital:							
Third-Party long-term debt		291.7	(7.1)	284.6	-	(29.3)	255.3
Deemed long-term debt		(3.4)	(17.6)	(21.0)	1.5	28.0	8.5
Short-term debt		18.3	(0.2)	18.1	0.1	(10.9)	7.3
AFUDC return on Niagara Reinforcement Project	see below	5.6	(0.3)	5.3	-	(0.0)	5.3
Total return on debt		**$ 312.3**	**$ (25.1)**	**$ 287.1**	**$ 1.6**	**$ (12.3)**	**$ 276.4**
Common equity		**$ 380.4**	**$ (28.3)**	**$ 352.1**	**$ 1.9**	**$ (23.4)**	**$ 330.6**
AFUDC return on Niagara Reinforcement Project							
CWIP		99.1		99.1			99.1
Deemed long-term debt		5.7%		5.40%			5.37%
		5.6		5.3			5.3

Note 1: As per EB-2010-0002 Decision with Reasons on December 23, 2010, the 2012 long-term debt rates have been updated to reflect the actual 2011 debt issuances and the September 2011 Consensus forecast.
Note 2: 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.
Note 3: The approved rates follow the OEB's November 10, 2011 guidance on cost of capital parameters to reflect the September 2011 Consensus Forecast.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2012)
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/11 ($Millions)	Total Amount Outstanding: at 12/31/12 ($Millions)	Avg. Monthly Averages ($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	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	0.0	73.6	4.3	
4	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	
5	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	0.0	159.9	9.1	
6	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	
7	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	
8	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	
9	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	
10	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	
11	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
12	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	
13	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	
14	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	
15	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	
16	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	
17	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	
18	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	
19	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
20	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.87	4.33%	130.0	130.0	130.0	5.6	
21	3-Mar-09	6.030%	3-Mar-39	195.0	1.1	193.9	99.43	6.07%	195.0	195.0	195.0	11.8	
22	16-Jul-09	5.490%	16-Jul-40	210.0	1.3	208.7	99.37	5.53%	210.0	210.0	210.0	11.6	
23	19-Nov-09	3.130%	19-Nov-14	175.0	0.6	174.4	99.64	3.21%	175.0	175.0	175.0	5.6	
24	15-Mar-10	5.490%	16-Jul-40	120.0	(0.7)	120.7	100.59	5.45%	120.0	120.0	120.0	6.5	
25	15-Mar-10	4.400%	1-Jun-20	180.0	0.8	179.2	99.56	4.45%	180.0	180.0	180.0	8.0	
26	13-Sep-10	2.950%	11-Sep-15	150.0	0.5	149.5	99.64	3.03%	150.0	150.0	150.0	4.5	
27	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.27	4.98%	150.0	150.0	150.0	7.5	
28	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	Note 1
29	15-Dec-11	3.786%	15-Dec-21	175.0	0.9	174.1	99.50	3.85%	175.0	175.0	175.0	6.7	Note 1
30	15-Mar-12	4.957%	15-Mar-42	225.0	1.1	223.9	99.50	4.99%	0.0	225.0	173.1	8.6	Note 2
31	15-Jun-12	3.936%	15-Jun-22	225.0	1.1	223.9	99.50	4.00%	0.0	225.0	121.2	4.8	Note 2
32	15-Sep-12	2.900%	15-Sep-17	225.0	1.1	223.9	99.50	3.01%	0.0	225.0	69.2	2.1	Note 2
33		**Subtotal**							4434.1	4833.2	4755.1	247.5	
34		Treasury OM&A costs										2.1	
35		Other financing-related fees										5.7	
36		**Total**							4434.1	4833.2	4755.1	255.3	5.37%

Note 1: As per EB-2010-0002 Decision with Reasons on December 23, 2010, long-term debt rates have been updated to reflect actual 2011 debt issuances.
Note 2: Rates have been updated to reflect September 2011 Consensus forecast as per OEB's November 10, 2011 direction on cost of capital parameters.

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Income Tax

($ millions)	Supporting Reference	Hydro One Proposed 2012	OEB Decision Impact 2012	OEB Approved 2012	US GAAP Impact 2012	Cost of Capital Update 2012	Revised OEB Approved 2012
Income Taxes	*See supporting details below*	70.0	(9.4)	60.6	(0.8)	(8.3)	51.4

Income Tax Supporting Details			Hydro One Proposed 2012	OEB Decision Impact 2012	OEB Approved 2012	US GAAP Impact 2012	Cost of Capital Update 2012	Revised OEB Approved 2012
Rate Base	Exhibit 1.2	a	$ 9,134.6	$ (408.3)	$ 8,726.3	48.1	0.0	8774.4
Common Equity Capital Structure		b	40.0%		40.0%	40.0%	40.0%	40.0%
Return on Equity	Exhibit 1.4	c	10.41%	-0.32%	10.09%	10.09%	-0.67%	9.42%
Return on Equity		d = a x b x c	380.4	(28.3)	352.1	1.9	(23.4)	330.6
Regulatory Income Tax		e = l	70.0	(9.4)	60.6	(0.8)	(8.3)	51.4
Regulatory Net Income (before tax)		f = d + e	450.3	(37.7)	412.6	1.1	(31.7)	382.0
Timing Differences *(Note 1)*		g	(175.6)	8.0	(167.7)	(4.2)	-	(171.8)
Taxable Income		h = f + g	274.7	(29.7)	245.0	(3.0)	(31.7)	210.2
Tax Rate		i	26.3%	26.3%	26.3%	26.3%	26.3%	26.3%
Income Tax		j = h x i	72.1	(7.8)	64.3	(0.8)	(8.3)	55.2
less: Income Tax Credits		k	(2.2)	(1.6)	(3.8)	-	-	(3.8)
Regulatory Income Tax		l = j + k	70.0	(9.4)	60.6	(0.8)	(8.3)	51.4

		OEB Decision Impact 2012	US GAAP Impact 2012
Note 1. Book to Tax Timing Differences			
Timing difference adjustments			
less: lower depreciation due to capex reductions	Exhibit 1.2	(4.1)	2.0
	EB-2010-0002 Decision Reference		
add: CCA changes related to capex reductions			
Adjustment for HST	Page 30	4.6	
Adjustment for AFUDC rate	Page 31	0.4	
D43 and D44 Adjustment	Page 43	1.0	
Bruce x Milton AFUDC add back	Page 47	(0.7)	
IFRS Accounting for Overheads Capitalized	Page 62	6.2	(6.2)
add: Tax adjustments			
Tax Adjustments to CCA		(1.1)	
Ontario credit addback		1.6	
		8.0	(4.2)

Hydro One Networks Inc.
2012 Rate Order

External Revenue

($ millions)	**Supporting Reference**	**Hydro One Proposed 2012**	**OEB Decision Impact 2012**	**OEB Approved 2012**	**US GAAP Impact 2012**	**Cost of Capital Update 2012**	**Revised OEB Approved 2012**
External Revenue		24.7	4.0	28.7	-	-	28.7

External Revenue Details	Hydro One Proposed 2012	OEB Decision Impact 2012	OEB Approved 2012	US GAAP Impact 2012	Cost of Capital Update 2012	Revised OEB Approved 2012
EB-2010-0002 Decision Reference Page 51						
Secondary Land Use	12.5	-	12.5	-	-	12.5
Station Maintenance	3.0	4.0	7.0	-	-	7.0
Engineering & Construction	6.0	-	6.0	-	-	6.0
Other	3.2	-	3.2	-	-	3.2
Total	24.7	4.0	28.7	-	-	28.7

Hydro One Networks Inc.
2012 Rate Order

Export Transmission Service Revenue

($ millions)	**Supporting Reference**	**Hydro One Proposed 2012**	**OEB Decision Impact 2012**	**OEB Approved 2012**	**US GAAP Impact 2012**	**Cost of Capital Update 2012**	**Revised OEB Approved 2012**
	EB-2010-0002 Decision Reference						
Export Transmission Service Revenue	Page 54	(10.2)	(5.8)	(16.0)	-	-	(16.0)

Hydro One Networks Inc.
2012 Rate Order

Deferral and Variance Accounts

($ millions)	Supporting Reference	Hydro One Proposed 2012	OEB Decision Impact 2012	OEB Approved 2012	US GAAP Impact 2012	Cost of Capital Update 2012	Revised OEB Approved 2012
Deferral and Variance Accounts	Page 55-56	2.6	(2.6)	-	-	-	-

Deferral and Variance Accounts Details	Hydro One Proposed 2012	OEB Decision Impact 2012	OEB Approved 2012	US GAAP Impact 2012	Cost of Capital Update 2012	Revised OEB Approved 2012
EB-2010-0002 Decision Reference Page 55-56						
Export Service Credit Revenue		-				-
External Secondary Land Use		-				-
External Station Maint. & E&CS		-				-
IPSP & Other LT Proj. Planning	1.0	(1.0)				-
Pension Cost Differential	1.6	(1.6)				-
Total	2.6	(2.6)	-	-	-	-

Hydro One Networks Inc.
2012 Rate Order
Continuity of Revenue Requirement

	H1 Proposed Submission	Remove CWIP	BxM AFUDC	HST	OM&A	AFUDC	Cost of Capital	D43 & D44	Tax Adjustments	IFRS	OEB Decision Impact Total Adjustments	OEB Approved	US GAAP Impact Adjustmer	Cost of Capital Update	Revised OEB Approved
	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012
Revenue Requirement															
OM&A	450.0	0.0	0.0	(5.1)	(17.8)	0.0	0.0	0.0	0.0	200.0	177.1	627.1	(200.0)	0.0	427.1
Depreciation	334.8	0.0	0.4	(1.7)	0.0	(0.2)	0.0	(0.5)	0.0	(2.0)	(4.1)	330.8	2.0	0.0	332.8
Return on debt	312.2	(9.7)	0.6	(1.8)	(0.0)	(0.3)	(11.5)	(0.8)	0.0	(1.6)	(25.1)	287.1	1.6	(12.3)	276.4
Return on common equity	380.4	(12.0)	0.7	(2.2)	(0.0)	(0.4)	(11.4)	(1.0)	0.0	(1.9)	(28.3)	352.1	1.9	(23.4)	330.6
Income tax	70.0	(4.3)	0.1	0.3	(0.0)	(0.1)	(4.0)	(0.2)	(2.0)	0.8	(9.4)	60.6	(0.8)	(8.3)	51.5
	1547.4	(26.0)	1.8	(10.5)	(17.9)	(1.1)	(26.9)	(2.5)	(2.0)	195.3	110.3	1657.6	(195.3)	(43.9)	1418.4
Rate Base	9134.6	(289.0)	18.0	(53.3)	(1.1)	(10.3)	0.0	(24.6)	0.0	(48.1)	(408.3)	8726.3	48.1	0.0	8774.4
Capex	1008.3	0.0	35.5	(30.6)	0.0	(2.1)	0.0	(29.8)	0.0	(200.0)	(227.0)	781.3	200.0	0.0	981.3
EB-2010-0002 Decision Reference		Page 47	Page 47	Page 30	Page 11	Page 31	Page 50	Page 43	Page 11	Page 62				Page 50	
EB-2011-0268 Decision Reference													Page 12	Page 14	

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2010-0002 and EB-2011-0268

Final 2012 Revenue Requirement by Rate Pool

	Supporting Exhibit	2012 Rate Pool Revenue Requirement ($ Million)					
		Network	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.1*	210.9	38.1	105.5	354.5	0.4	354.9
Other Taxes (Grants-in-Lieu)	*Note 1*	45.4	10.4	16.4	72.2	0.0	72.2
Depreciation of Fixed Assets	*1.2*	191.3	41.3	83.0	315.7	0.1	315.7
Capitalized Depreciation	*Note 2*	(5.5)	(1.3)	(2.0)	(8.8)	(0.0)	(8.8)
Asset Removal Costs	*Note 2*	11.3	2.6	4.2	18.1	0.0	18.1
Other Amortization	*Note 2*	4.9	1.1	1.8	7.8	0.0	7.8
Return on Debt	*1.4*	173.7	39.7	63.0	276.4	0.1	276.4
Return on Equity	*1.4*	207.8	47.5	75.3	330.6	0.1	330.6
Income Tax	*1.5*	32.3	7.4	11.7	51.4	0.0	51.4
Base Revenue Requirement		**872.1**	**186.8**	**358.9**	**1417.8**	**0.6**	**1418.4**
Less Regulatory Asset Credit	*1.8*	0.0	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement		**872.1**	**186.8**	**358.9**	**1417.8**	**0.6**	**1418.4**
Less Non-Rate Revenues	*1.6*	(17.7)	(3.8)	(7.3)	(28.7)	(0.0)	(28.7)
Less Export Revenues	*1.7*	(16.0)			(16.0)		(16.0)
Plus LVSG Credit	*6.0*			11.5	11.5		11.5
Total Revenue Requirement for UTR		**838.5**	**183.0**	**363.1**	**1384.6**	**0.6**	**1385.1**
Hydro One Proposed Pool Revenue Requirement	*Note 3*	933.0	201.1	392.7	1526.8	0.6	1527.5

Note 1: Included with OM&A total in Exhibit 1.1. See EB-2010-0002 Exhibit G2, Tab 5, Schedule 1, Page 2.
Note 2: Included with Depreciation total in Exhibit 1.2. See EB-2010-0002 Exhibit G2, Tab 5, Schedule 1, Page 2.
Note 3: See EB-2010-0002 Exhibit G2, Tab 5, Schedule 1, Page 2.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2010-0002 and EB-2011-0268

Final 2012 Charge Determinants
(for Setting Uniform Transmission Rates for January 1, 2012 to December 31, 2012)

	Total MW *
Network	238,134
Line Connection	231,434
Transformation Connection	200,008

* *2012 charge determinants per EB-2010-0002 Exhibit H1, Tab 3, Schedule 1, Table 1, multiplied by 12.*

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2010-0002 and EB-2011-0268

Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2012 to December 31, 2012)

Transmitter	Revenue Requirement ($) *(Note 3, Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,831,576	$836,127	$1,659,387	$6,327,089
CNPI	$2,793,216	$609,536	$1,209,692	$4,612,443
GLPT	$21,345,462	$4,658,009	$9,244,336	$35,247,808
H1N *(Note 1)*	$838,477,537	$182,972,674	$363,129,562	$1,384,579,773
All Transmitters	$866,447,790	$189,076,346	$375,242,977	$1,430,767,113

Transmitter	Total Annual Charge Determinants (MW) *(Note 3, Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	187.120	213.460	76.190	
CNPI	583.420	668.600	668.600	
GLPT	3,954.620	2,937.438	985.415	
H1N *(Note 2)*	238,134.047	231,433.958	200,008.248	
All Transmitters	242,859.207	235,253.456	201,738.453	

Transmitter	Uniform Rates and Revenue Allocators *(Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.57**	**0.80**	**1.86**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00442**	**0.00442**	**-**	
CNPI Allocation Factor	**0.00322**	**0.00322**	**0.00322**	
GLPT Allocation Factor	**0.02464**	**0.02464**	**0.02464**	
H1N Alocation Factor	**0.96772**	**0.96772**	**#VALUE!**	
Total of Allocation Factors	1.00000	1.00000	#VALUE!	

Note 1: Hydro One Networks (H1N) 2012 UTR Revenue Requirement per Exhibit 2.0

Note 2: Hydro One Networks (H1N) Charge Determinant per Exhibit 3.0

Note 3: Data for Other Transmitters per Exhibit 4.1

Note 4: Calculated data in shaded cells.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2010-0002 and EB-2011-0268

2012 Revenue Requirement and Charge Determinant Assumptions for Other Transmitters

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 (CNPI)	4,612,443	583.420	668.600	668.600	*Note 2*
Great Lakes Power Transmission (GLPT)	35,247,808	3,954.620	2,937.438	985.415	*Note 3*

Note 1: Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 2: 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 and Order on EB-2010-0291 dated on February 2, 2011, and 2012 Revenue Requirement Work Form submitted by GLPT to OEB in letter dated November 17, 2011.

ONTARIO TRANSMISSION RATE SCHEDULES

EB-2011-0268

The rate schedules contained herein shall be effective January 1, 2012

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, 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]	**3.57**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.80**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**1.86**

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.

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

Rate Schedule: HON-MET
Issued: To Be Determined
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-2010-0002 and EB-2011-0268

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)	
2012	75	0.6	7,900	8,400

* Rate is rounded down to the nearest $100

Note 1: Per EB-2010-0002 Exhibit H1, Tab 4, Schedule 1, Page 2.

Note 2: Per Exhibit 2.0

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2010-0002 and EB-2011-0268

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2012

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) x12
200,008	351.6	1.758	2879	19.0%	11.5

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-2010-0002 Exhibit G1, Tab 4, Schedule 1, Table 1

Note 4: See EB-2010-0002 Exhibit G1, Tab 4, Schedule 1, page 2.

Hydro One Networks Inc
Implementation of EB-2010-0002 and EB-2011-0268 Decision with Reasons
Studies and Reports

	EB-2010-0002 Decision Reference	EB-2011-0268 Decision Reference	Description	Actions Planned
CDM Measurement Study	Pages 6 & 7		Hydro One directed to work with the OPA in devising a robust effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA.	Hydro One has consulted with stakeholders and will complete the study in time for the next rate application
Smart Grid Development Report	Page 14		Hydro One to file a detailed report describing the OM&A activities for Smart Grid undertaken along with an analysis of the results achieved and a description of how they relate to the transmission system.	Hydro One will prepare the report in time for the next transmission rate application
Compensation Benchmarking Study	Page 20		Hydro One directed to revisit its compensation cost benchmarking study in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America.	Hydro One has consulted with stakeholders and will complete the study in time for the next transmission rate application
ETS Study by IESO	*Page 75*		*The IESO is to undertake a genuinely comprehensive study to identify a range of proposed rates and the pros and cons associated with each proposed rate.*	*Hydro One understands that IESO is targeting to publish the final report & submit to the OEB in March 2012*

	EB-2010-0002 Decision Reference	**EB-2011-0268 Decision Reference**	**Description**	**Actions Planned**
Capitalization Policy Review		Page 13	Hydro One to conduct a critical review of its current and proposed capitalization practices. This review should include what U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters, and compare those to Hydro One’s capitalization policies.	Hydro One will complete the review in time for the next transmission rate application

Hydro One Networks Inc.
Decision with Reasons on EB-2010-0002 and EB-2011-0268
Deferral and Variance Accounts

The Boards' Decisions directed the Company to continue or establish a number of deferral/variance accounts. The following table includes a list of those accounts:

Account Name	**EB-2010-0002 Decision Reference**	**EB-2011-0268 Decision Reference**
Rights Payments Variance Account - New	Page 21	
Bruce to Milton Project In-Service Variance Account - New	Page 28	
Pension Cost Differential Account	Page 59	
Long-term Project Development OM&A Account	Page 59	
Tax Rate Changes Account	Page 59	
Export Service Credit Revenue Variance Account	Page 54 & 60	
External Station Maintenance and E&CS Revenue Variance Account	Page 52 & 60	
External Secondary Land Use Revenue Variance Account	Page 52 & 60	
Impact for Change in IFRS Account (2012 Only) - Discontinued as per EB-2011-0268 Decision	Page 58	Page 12
IFRS – Gains and Losses Account (2012 Only) - Discontinued as per EB-2011-0268 Decision	Page 58	Page 12
IFRS Capitalization Policy Variance Account – Discontinued as per EB-2011-0268 Decision	Page 65	Page 12
IFRS Incremental Transition Cost Account	Page 58	
US GAAP Incremental Transition Cost Deferral Account – New as per EB-2011-0268 Decision		Page 12
Impact for US GAAP Variance Account – New as per EB-2011-0268 Decision		Page 12

In its EB-2011-0268 Decision, the Board approved the discontinuation of three of the Board's previously approved Deferral and Variance Accounts in its EB-2010-0002 Decision: Impact for Changes in IFRS Account, the IFRS - Gains and Losses Account and the IFRS Capitalization Policy Variance Account. Effective January 1, 2012, these accounts will be closed.

In the EB-2011-0268 Decision, the Board also approved the creation of two new accounts: US GAAP Incremental Transition Cost Deferral Account and the Impact for US GAAP Variance Account.