

Hydro One Networks Inc.

7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5700
Fax: (416) 345-5870
Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank

Vice President and Chief Regulatory Officer
Regulatory Affairs



BY EMAIL

September 19, 2014

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

Dear Ms. Walli:

**EB-2013-0416 Hydro One Networks' 2015 - 2019 Distribution Custom Rate Application
Undertaking Responses**

Please find enclosed responses to undertakings provided at the Oral Hearings in the above-noted proceeding and electronic copies of the exhibits which were physically distributed during the hearing. The following undertakings are being filed:

September 15, 2014 September 16, 2014 September 17, 2014

J5.3	J6.2	J7.1
J5.5	J6.4	J7.2
J5.9		J7.4
J5.10		
J5.11		
J5.12		
J5.13		

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

cc. Intervenor

Encls.

UNDERTAKING – J5.3

Undertaking

To explain how financial benefits relate to the business values.

Response

Investments can be undertaken to mitigate risks to Hydro One's business values, or for the purposes of financial benefits, and in some cases accomplish both. For an investment with financial benefits, each alternative is assessed based on the dollars of cost savings expected for the company. The financial benefits are therefore used in the Asset Investment Planning tool to assist in the evaluation and prioritization of the investment in a similar manner as the risk mitigation to Hydro One's business values.

UNDERTAKING – J5.5

Undertaking

To provide the number of stations on that list that qualify for the full replacement treatment, which would then also be subject to the efficiency improvement in getting the modular station.

Response

Of the 194 distribution stations planned for refurbishment over the 5 year period, approximately 56 distribution stations will be a full remove and replace with new equipment. However as outlined in interrogatory response Exhibit I, Tab 3.02, Schedule 11 EP 30; Hydro One is planning to install approximately six integrated modular distribution stations (“iMDS”) per year over the 5 year plan dependent on the success of the iMDS pilot project.

UNDERTAKING – J5.9

Undertaking

To confirm whether or not that 24 percent captures one or two categories.

Response

Hydro One can confirm that the 24% of distribution station transformer condition assessments that fall in the high risk category, as outlined in Exhibit D1, Tab 2, Schedule 1 page 5, include the distribution station transformers that are showing up as Red and Orange under the condition risk factor in the Asset Analytics tool.

The table below summarizes the percentage of assets that have condition assessments that fall in the high risk category for the other distribution assets identified in Exhibit D1, Tab 2, Schedule 2.

Distribution Asset	High Risk Category for Condition
Station Reclosers / Breakers	64%
Station Switches and Fuses	6%
Mobile Unit Substations	18%
Poles	4%
Line Transformers	1%
Submarine Cables	10%

Note: “Right of Ways” is not included in the table since the driving factor is to achieve an 8 year cycle in order to reduce lifecycle costs.

UNDERTAKING – J5.10

Undertaking

To provide a history of the cycles.

Response

The following graph outlines the actual vegetation line clearing accomplishment levels achieved each year from 2004 to 2013. The dotted line represents the sustained accomplishment level required to achieve an 8 year line clearing cycle.



As the graph demonstrates, Hydro One has not achieved the level of accomplishment required to sustain an 8 year line clearing cycle to date. The 2007 and 2008 accomplishment levels represented about an 8 year cycle. However, Hydro One's right-of-ways were still on an average cycle length of 10 years, as was documented in the Hydro One 2009 Vegetation Management Benchmarking Study.

In proceeding EB-2009-0096, Hydro One proposed to implement an accomplishment level by 2011 that would result in a 7 year cycle. However, as indicated in interrogatory response Exhibit I, Tab 3.01, Schedule 1 Staff 40, with the Board's Decision to reduce the overall OM&A spending envelope by \$40 million in each of the test years (2010 and 2011), Hydro One made a business decision to discontinue plans for a 7 year clearing cycle.

Filed: 2014-09-19

EB-2013-0416

Exhibit J5.10

Page 2 of 2

- 1 Hydro One's current clearing cycle is averaging 9.5 years. Hydro One is proposing in this
- 2 application line clearing accomplishment levels which will sustain an 8-year clearing
- 3 cycle which will benefit life-cycle costs.

UNDERTAKING – J5.11

Undertaking

To confirm whether they would be putting an extra \$10-million in capital expenditures or the revenue requirement of \$10-million, so \$100-million into capital expenditures.

Response

If Hydro One finds \$10 million in productivity savings from OM&A, the company will invest those savings back into its work program to address the system needs identified through continuous monitoring and repriorization. This will most likely be in other OM&A programs. However, given the revenue available with the approved rates, Hydro One might give priority to a capital investment that has a revenue requirement of \$10 million. Due to resourcing and other constraints associated with capital projects, Hydro One will more likely invest the OM&A savings back into its OM&A work program.

UNDERTAKING – J5.12

Undertaking

To explain the entries and the scoring system in the chart for both the customer risk and the reliability.

Response

Hydro One's investment prioritization process is based on a risk mitigation approach. When assessing the level of risk for an investment, both severity and probability are considered. The probability scale ranges from "Unexpected" to "Very Likely"; whereas the severity scale ranges from "Minor" to "Worst Case". Severity levels are assigned based on the anticipated results from the investment, while probability is assigned based on the likelihood of the results occurring within the five year period. For customer risk, the main considerations are impacts to customer satisfaction, complaint volumes and production losses for large customers. For reliability risk, the main considerations are the impact to overall SAIDI and SAIFI performance values.

For the line clearing example, an initial baseline risk is first established by considering the overall impact if no investment is pursued. In the absence of any funding, there is a "medium" chance (i.e. between 25% and 65%) that "major" customer impacts could occur within the five year period, such as a noticeable increase in customer complaints, and production losses for large distribution customers. For reliability, there is a "very likely" chance (i.e. greater than 95%) that there will be "major" to "severe" impacts within the five year period that would result in a deterioration of Hydro One's reliability SAIDI and SAIFI values.

The Impact Risk is then established for each of the alternative spend levels. In this example the "Intermediate 1" for line clearing represents the proposed funding profile that moves towards an 8 year clearing cycle. The resulting customer risk associated with this level of investment is a "minor" to "moderate" customer impact with a "likely" (i.e. 65% to 95%) probability to occur within the five year period. In comparison to the baseline, this alternative offers a higher level of customer satisfaction and a reduction in customer complaints. The reliability risk associated with this funding level is a "moderate" impact to reliability performance with a "likely" (i.e. 65% to 95%) probability to occur within the five year period. As the severity and probability are reduced in comparison to the baseline, the proposed investment is expected to reduce the impact on Hydro One's SAIDI and SAIFI performance. Overall, the "Intermediate 1" will reduce the current customer and reliability risks throughout the five year period.

In order to prioritize investments, quantitative values are assigned to each risk level based on the level of probability and severity selected; such that the risk mitigated per dollar of investment can be compared across all investments.

UNDERTAKING – J5.13

Undertaking

To comment on whether granularity of the force majeure metric could be improved.

Response

The proposed outcome measure for vegetation management is the number of vegetation caused interruptions, excluding those that occur during ‘force majeure’ events.

The focus of the proposed outcome measure is to measure the effectiveness of the vegetation management program. The ‘force majeure’ events are often triggered by unusually intense environmental conditions. These conditions can often cause damage to healthy trees that are not normally targeted as part of the vegetation management program, leading to an unpredictable number of vegetation caused interruptions. To increase the relevance and reduce the variability of the proposed outcome measure, vegetation caused interruptions that occur during ‘force majeure’ events are excluded.

The following table illustrates the variability of the actual number of vegetation caused interruptions including and excluding those occurring during ‘force majeure’ events over the 2009 to 2013 period. The table provides the proposed targets for the number of interruptions that exclude ‘force majeure’ events. The number of interruptions for the 2014 to 2019 period, if the outcome measure was to be based on all interruptions including ‘force majeure’ events, is also reflected using the historical average with minor improvements forecast.

	Actuals					Targets					
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Proposed: Number of Interruptions (excluding force majeure)	6,445	6,116	6,113	6,953	5,791	6,300	6,300	6,300	6,200	6,100	6,000
Number of Interruptions (including force majeure)	8,572	7,747	14,047	9,797	17,279	11,500	11,500	11,500	11,400	11,300	11,100

UNDERTAKING – J6.2

Undertaking

To prepare a table showing rate impacts isolated from the effects of smoothing and rate riders.

Response

The table in Attachment #1 provides the bill impacts for 2015 to 2019 by rate class assuming unsmoothed revenue requirement and deleting all riders in 2014 and 2015 to 2019. The smart meter rate adder in 2014 as been left in to provide results on a comparable basis given that the 2015 to 2019 base distribution rates include smart meter costs as part of the base revenue requirement used to set rates.

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2015				2016				2017				2018				2019			
				Change in DX Bill (\$)	Change in DX Bill (%)	Change in Total Bill (\$)	Change in Total Bill (%)	Change in DX Bill (\$)	Change in DX Bill (%)	Change in Total Bill (\$)	Change in Total Bill (%)	Change in DX Bill (\$)	Change in DX Bill (%)	Change in Total Bill (\$)	Change in Total Bill (%)	Change in DX Bill (\$)	Change in DX Bill (%)	Change in Total Bill (\$)	Change in Total Bill (%)	Change in DX Bill (\$)	Change in DX Bill (%)	Change in Total Bill (\$)	Change in Total Bill (%)
UR	Low	100		\$3.01	15.7%	\$2.82	8.5%	\$0.63	2.8%	\$0.64	1.8%	(\$0.37)	-1.6%	(\$0.38)	-1.0%	(\$0.72)	-3.2%	(\$0.73)	-2.0%	(\$0.38)	-1.7%	(\$0.39)	-1.1%
	Typical	800		(\$2.57)	-6.9%	(\$4.54)	-3.2%	\$1.05	3.0%	\$1.07	0.8%	(\$0.58)	-1.6%	(\$0.59)	-0.4%	(\$1.07)	-3.1%	(\$1.09)	-0.8%	(\$0.52)	-1.5%	(\$0.53)	-0.4%
	High	2,000		(\$12.13)	-17.9%	(\$17.16)	-5.3%	\$1.77	3.2%	\$1.80	0.6%	(\$0.94)	-1.6%	(\$0.96)	-0.3%	(\$1.67)	-3.0%	(\$1.70)	-0.5%	(\$0.76)	-1.4%	(\$0.77)	-0.3%
R1	Low	100		\$3.81	13.9%	\$3.67	8.8%	\$1.43	4.6%	\$1.45	3.2%	(\$0.31)	-0.9%	(\$0.32)	-0.7%	(\$0.93)	-2.9%	(\$0.95)	-2.0%	(\$0.42)	-1.3%	(\$0.43)	-0.9%
	Typical	800		\$1.85	3.6%	\$0.22	0.1%	\$2.48	4.7%	\$2.52	1.6%	(\$0.52)	-0.9%	(\$0.53)	-0.3%	(\$1.49)	-2.7%	(\$1.52)	-1.0%	(\$0.56)	-1.0%	(\$0.57)	-0.4%
	High	2,000		(\$1.51)	-1.6%	(\$5.70)	-1.6%	\$4.28	4.7%	\$4.35	1.3%	(\$0.88)	-0.9%	(\$0.89)	-0.3%	(\$2.45)	-2.6%	(\$2.49)	-0.7%	(\$0.80)	-0.9%	(\$0.81)	-0.2%
R2	Low	100		\$5.28	14.4%	\$5.43	10.6%	\$5.68	13.5%	\$5.78	10.2%	\$2.65	5.6%	\$2.70	4.3%	\$2.46	4.9%	\$2.50	3.8%	\$2.53	4.8%	\$2.57	3.8%
	Typical	800		\$11.20	17.8%	\$11.90	7.1%	\$8.48	11.5%	\$8.62	4.8%	\$4.05	4.9%	\$4.12	2.2%	\$4.07	4.7%	\$4.14	2.1%	\$4.21	4.6%	\$4.28	2.2%
	High	2,000		\$21.35	19.9%	\$23.00	6.2%	\$13.28	10.3%	\$13.51	3.5%	\$6.45	4.5%	\$6.56	1.6%	\$6.83	4.6%	\$6.95	1.7%	\$7.09	4.6%	\$7.21	1.7%
Seasonal	Low	50		\$3.36	12.1%	\$3.39	9.5%	\$2.25	7.2%	\$2.28	5.8%	\$1.39	4.2%	\$1.41	3.4%	\$0.80	2.3%	\$0.81	1.9%	\$1.06	3.0%	\$1.07	2.5%
	Typical	400		\$6.32	11.2%	\$6.22	5.7%	\$4.80	7.6%	\$4.88	4.2%	\$2.82	4.2%	\$2.87	2.4%	\$1.78	2.5%	\$1.81	1.5%	\$2.49	3.5%	\$2.53	2.0%
	High	1,000		\$11.38	10.8%	\$11.08	4.7%	\$9.18	7.8%	\$9.34	3.8%	\$5.28	4.2%	\$5.37	2.1%	\$3.46	2.6%	\$3.52	1.3%	\$4.95	3.7%	\$5.03	1.9%
GSe	Low	1,000		\$3.79	4.7%	\$4.99	2.4%	\$6.04	7.2%	\$6.14	2.9%	\$2.65	2.9%	\$2.70	1.2%	\$1.80	1.9%	\$1.83	0.8%	\$2.40	2.5%	\$2.44	1.1%
	Typical	2,000		\$17.34	14.4%	\$19.91	5.3%	\$9.84	7.1%	\$10.01	2.5%	\$4.35	2.9%	\$4.42	1.1%	\$3.20	2.1%	\$3.25	0.8%	\$4.30	2.8%	\$4.37	1.1%
	High	15,000		\$193.49	30.1%	\$233.72	8.5%	\$59.24	7.1%	\$65.40	2.2%	\$26.45	3.0%	\$29.20	1.0%	\$21.40	2.3%	\$23.66	0.8%	\$29.00	3.1%	\$32.07	1.0%
UGe	Low	1,000		\$16.19	52.3%	\$14.81	9.3%	\$3.11	6.6%	\$3.16	1.8%	\$3.22	6.4%	\$3.27	1.9%	\$2.40	4.5%	\$2.44	1.4%	\$2.56	4.6%	\$2.60	1.4%
	Typical	2,000		\$23.35	48.8%	\$20.43	6.8%	\$4.61	6.5%	\$4.69	1.5%	\$4.82	6.4%	\$4.90	1.5%	\$3.70	4.6%	\$3.76	1.1%	\$4.06	4.8%	\$4.13	1.2%
	High	15,000		\$116.43	43.7%	\$101.02	4.3%	\$24.11	6.3%	\$26.55	1.1%	\$25.62	6.3%	\$28.23	1.1%	\$20.60	4.8%	\$22.71	0.9%	\$23.56	5.2%	\$25.99	1.0%
GSd	Low	15,000	60	\$165.04	22.2%	\$166.41	5.9%	\$93.06	10.3%	\$105.16	3.5%	\$84.80	8.5%	\$95.83	3.1%	\$75.47	7.0%	\$85.29	2.7%	\$76.52	6.6%	\$86.47	2.7%
	Typical	35,000	120	\$302.31	21.2%	\$301.44	4.9%	\$178.55	10.3%	\$201.76	3.1%	\$162.57	8.5%	\$183.71	2.8%	\$145.97	7.0%	\$164.94	2.4%	\$148.17	6.7%	\$167.44	2.4%
	High	175,000	500	\$1,171.67	20.3%	\$1,156.63	4.0%	\$719.97	10.4%	\$813.57	2.7%	\$655.13	8.5%	\$740.30	2.4%	\$592.43	7.1%	\$669.45	2.1%	\$601.97	6.8%	\$680.23	2.1%
UGd	Low	15,000	60	\$107.81	24.0%	\$116.44	4.7%	\$55.32	9.9%	\$62.51	2.4%	\$51.68	8.4%	\$58.40	2.2%	\$45.31	6.8%	\$51.20	1.9%	\$46.08	6.5%	\$52.07	1.9%
	Typical	35,000	120	\$163.25	18.9%	\$168.00	3.0%	\$102.74	10.0%	\$116.09	2.0%	\$95.71	8.5%	\$108.15	1.9%	\$85.03	6.9%	\$96.09	1.6%	\$86.66	6.6%	\$97.92	1.6%
	High	175,000	500	\$514.33	14.7%	\$479.35	1.8%	\$403.05	10.0%	\$455.45	1.7%	\$374.55	8.5%	\$423.24	1.6%	\$336.63	7.0%	\$380.39	1.4%	\$343.65	6.7%	\$388.32	1.4%
St Lgt	Low	100		\$4.33	49.5%	\$4.37	21.0%	\$1.18	9.0%	\$1.20	4.8%	\$0.68	4.8%	\$0.69	2.6%	\$0.56	3.7%	\$0.57	2.1%	\$0.58	3.7%	\$0.59	2.1%
	Typical	500		\$11.46	30.2%	\$11.49	11.8%	\$4.42	9.0%	\$4.50	4.1%	\$2.68	5.0%	\$2.73	2.4%	\$2.20	3.9%	\$2.24	1.9%	\$2.18	3.7%	\$2.22	1.9%
	High	2,000		\$38.19	25.9%	\$38.20	9.4%	\$16.57	8.9%	\$16.85	3.8%	\$10.18	5.0%	\$10.35	2.2%	\$8.35	3.9%	\$8.49	1.8%	\$8.18	3.7%	\$8.32	1.7%
Sen Lgt	Low	20		\$1.22	34.9%	\$1.24	20.1%	\$0.66	13.9%	\$0.67	9.1%	\$0.48	8.9%	\$0.48	6.0%	\$0.39	6.6%	\$0.39	4.6%	\$0.23	3.7%	\$0.23	2.6%
	Typical	50		\$1.67	25.8%	\$1.68	13.3%	\$1.11	13.5%	\$1.12	7.8%	\$0.80	8.6%	\$0.81	5.2%	\$0.65	6.5%	\$0.66	4.0%	\$0.36	3.4%	\$0.37	2.2%
	High	200		\$3.93	18.3%	\$3.93	8.6%	\$3.34	13.1%	\$3.40	6.9%	\$2.42	8.4%	\$2.46	4.7%	\$1.97	6.3%	\$2.00	3.6%	\$1.02	3.1%	\$1.04	1.8%
USL	Low	100		\$8.76	26.0%	\$8.78	18.9%	\$0.07	0.2%	\$0.07	0.1%	(\$0.17)	-0.4%	(\$0.17)	-0.3%	(\$1.41)	-3.3%	(\$1.43)	-2.6%	(\$0.59)	-1.4%	(\$0.60)	-1.1%
	Typical	500		\$4.95	9.9%	\$4.38	4.0%	(\$0.09)	-0.2%	(\$0.09)	-0.1%	(\$0.41)	-0.7%	(\$0.42)	-0.4%	(\$1.85)	-3.4%	(\$1.88)	-1.6%	(\$0.75)	-1.4%	(\$0.76)	-0.7%
	High	1,000		\$0.17	0.2%	(\$1.13)	-0.6%	(\$0.29)	-0.4%	(\$0.29)	-0.2%	(\$0.71)	-1.0%	(\$0.72)	-0.4%	(\$2.40)	-3.5%	(\$2.44)	-1.3%	(\$0.95)	-1.4%	(\$0.97)	-0.5%
DGen	Low	300	10	\$99.11	97.6%	\$115.08	73.1%	\$55.41	27.6%	\$62.61	23.0%	\$45.53	17.8%	\$51.45	15.4%	\$41.34	13.7%	\$46.71	12.1%	\$31.06	9.1%	\$35.09	8.1%
	Typical	2,000	20	\$72.25	44.9%	\$87.82	20.3%	\$70.74	30.3%	\$79.94	15.4%	\$60.46	19.9%	\$68.32	11.4%	\$55.06	15.1%	\$62.22	9.3%	\$42.78	10.2%	\$48.35	6.6%
	High	5,000	100	(\$142.62)	-22.4%	(\$130.27)	-9.4%	\$193.44	39.1%	\$218.59	17.5%	\$179.91	26.2%	\$203.30	13.9%	\$164.88	19.0%	\$186.31	11.2%	\$136.60	13.2%	\$154.36	8.3%
ST	Low	200,000	500	\$574.34	51.5%	\$929.58	3.4%	\$158.37	9.4%	\$178.96	0.6%	\$68.64	3.7%	\$77.56	0.3%	\$89.39	4.7%	\$101.01	0.4%	\$85.48	4.3%	\$96.59	0.3%
	Typical	500,000	1,000	\$794.69	54.5%	\$1,459.16	2.2%	\$222.02	9.9%	\$250.88	0.4%	\$102.74	4.2%	\$116.10	0.2%	\$122.74	4.8%	\$138.70	0.2%	\$120.63	4.5%	\$136.31	0.2%
	High	4,000,000	10,000	\$4,760.99	62.7%	\$10,991.50	2.1%	\$1,367.72	11.1%	\$1,545.52	0.3%	\$716.54	5.2%	\$809.69	0.1%	\$723.04	5.0%	\$817.04	0.1%	\$753.33	5.0%	\$851.26	0.2%

UNDERTAKING – J6.4

Undertaking

To show the 2014 current fixed and variable charges, the as-filed fixed and variable charges, and what the fixed and variable charges would be using the updated minimum system value.

Response

The table below shows the requested information including the 2015 updated fixed and variable charges based on a change to the “minimum system for conductors” value used in the “E1 Categorization” tab of the 2015 cost allocation model from the current value of 54.8% to the value of 51.1% as proposed by Mr. Marcus on page 4 of GEC’s evidence.

Hydro One believes this change to be appropriate and will be made to the 2015 to 2019 cost allocation models used to establish rates for the Draft Rate Order to be prepared following the Board’s Decision on this application.

Rate Class	2014 (Current Rates)			2015 (As-Filed)			2015 (Update to As-Filed)		
	Fixed Charge (\$/month)	Volumetric Charge (\$/kWh)	Volumetric Charge (\$/kW)	Fixed Charge (\$/month)	Volumetric Charge (\$/kWh)	Volumetric Charge (\$/kW)	Fixed Charge (\$/month)	Volumetric Charge (\$/kWh)	Volumetric Charge (\$/kW)
UR	12.72	0.02557		20.45	0.0176		19.92	0.0180	
R1	20.15	0.03390		28.16	0.0311		27.14	0.0319	
R2	57.61	0.03724		67.96	0.0457		67.96	0.0458	
Seasonal	19.71	0.08206		26.57	0.0905		25.60	0.0900	
GSe	35.92	0.04025		30.08	0.0538		28.28	0.0547	
UGe	10.20	0.01684		23.15	0.0240		22.37	0.0246	
GSd	52.27		11.433	83.96		13.7208	81.58		14.0424
UGd	28.71		6.935	85.01		7.8589	83.72		8.0401
St Lgt	1.47	0.07288		4.02	0.0907		4.02	0.0899	
Sen Lgt	1.50	0.09986		2.42	0.1149		2.42	0.1133	
USL	29.69	0.04025		39.41	0.0307		38.37	0.0303	
DGen	38.13		5.951	168.02		3.2651	167.46		3.2946
ST-Service Charge	294.97			453.70			450.37		
ST-Meter Charge	476.35			675.53			674.00		
ST-Common Line Charge			0.682			1.1227			1.1410
ST-Specific ST Line Charge*			647.16			960.9097			972.3820
ST-Specific Primary Line Charge*			501.55			722.7036			731.3319
ST-HVDS-High Charge			1.632			1.8444			1.8444
ST-HVDS-Low Charge			3.618			3.8691			3.8973
ST-LVDS-Low Charge			1.987			2.0247			2.0529

* These are \$/km charges.

UNDERTAKING – J7.1

Undertaking

To update the table so that it shows the draft target.

Response

The table below shows the updated savings from Other Programs/Future Programs (Item 8) using Hydro One's share of the Draft LDC Total 2015-2020 CDM Target (17.15%). The persisting savings from Non-Target and Target Programs as well as savings from Codes & Standards have not changed (Items 5, 6, and 7). Hydro One Distribution's (HOD) total CDM energy savings (Item 4) have been updated to reflect the change in Other Programs/Future Programs. Please note that the savings from Other Programs/Future Programs (Item 8) have not been adjusted using the half-year rule because detailed annual information was not available.

Items	2015	2016	2017	2018	2019
(1) LTEP 2013 Total energy saving	10,900	11,300	11,400	13,000	15,100
(2) Excluding saving from TX direct customers (at generation level)	953	1,106	1,259	1,412	1,565
(3) Total savings from all LDCs (at end use level)	9,339	9,571	9,522	10,880	12,709
(4) HOD Total energy savings	1,672	1,703	1,684	1,918	2,237
(5) HOD persisting savings from Non-Target Programs 2005 to 2010	335	289	257	219	178
(6) HOD persisting savings from Target programs 2011 to 2014	475	465	452	428	399
(7) HOD savings from codes and standards	358	387	417	527	637
(8) HOD savings from other programs/future programs (OPFP)	504	562	558	744	1,023

UNDERTAKING – J7.2

Undertaking

To confirm whether the costs are constant.

Response

During the conversation regarding holding regulatory charges constant, Hydro One accepted an undertaking to verify the dates the Clean Energy Benefit and Debt Retirement charges were to be removed from customers' bills. (Reference: EB-2103-0416, Volume 7, Wednesday, September 17, 2014, pages 66 to 68)

According to the Ministry of Finance, Ontario intends to take the **Debt Retirement Charge (DRC)** off residential electricity bills as of January 2016. The DRC will remain on all other electricity customers' bills (including large industrial users) until the stranded debt is retired. This is forecast to be near the end of 2018.

The Ontario **Clean Energy Benefit** went into effect on January 1, 2011 for a five year period. This rebate will end on December 31, 2015. In place of the Clean Energy Benefit, a new Ontario Electricity Support Program will be taking effect in early 2016 to assist eligible low-income residents. Details of the new program have not been announced. Other measures such as moving power use to off-peak times are being investigated to assist businesses and factories to save on their electricity bills.

UNDERTAKING – J7.4

Undertaking

To advise whether Dryden is being moved from urban to R1 or is already in R1.

Response

The Dryden density zone that has been identified includes 5019 Hydro One Distribution customers at a density of 20 customers per circuit kilometer of line, and as such it is classified as a medium density zone.

The vast majority of customers in Dryden are already classified as medium density (e.g. R1 residential) customers. Specifically, the Dryden medium density zone includes:

- 4210 residential customers of which 4045 are currently classified as medium density (R1 rate class), 3 are classified as high density (UR rate class), and 162 are classified as low density (R2 rate class)
- 632 general service energy (GSe) and 2 urban general service energy (UGe) customers
- 73 general service demand (GSd) customers
- 102 non-density based rate classes