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October 1, 2010

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Sreet, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli,

Re: Hydro One Brampton Networks Inc.'s 2011 Cost of Service Electricity Distribution Rate Application; EB-2010-0132

Please find enclosed responses to interrogatories of the Board Staff and the intervenors in the above-captioned proceeding.

Information associated with the School Energy Coalition interrogatory #5 has been prepared and submitted to the Ontario Energy Board in confidence as the response contains information that is commercially sensitive. Hydro One Brampton asks for confidential treatment of the attachment to this interrogatory response.

Hydro One Brampton is prepared to share a copy of the information submitted in confidence with intervenors that sign a Declaration and Undertaking form in accordance with the OEB Practice Direction on Confidential Filing.

Sincerely,

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INTERVENORS

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Hydro One Brampton Networks Inc.
2011 Cost of Service Electrical Distribution Rate Application
Interrogatory Responses
ED-2003-0038/EB-2010-0132
Filed: October 1, 2010

EXHIBIT 12
INTERROGATORY RESPONSES

EXHIBIT 12 TAB 1

ONTARIO ENERGY BOARD

Ontario Energy Board Interrogatory # 1

Ref: Exhibit 1 / Tab 3/ Schedule 3 – IFRS Implementation

On page 2, it states: "Depending on the outcome of the IASB project and their final decision, there could still be more changes that Hydro One Brampton may have to make as a result of IFRS. The subject of these changes is addressed in the proposed IFRS Variance Account…."

Please advise whether Hydro One Brampton foresees changes to its application based on any recent IASB project or decision that has not been included in this application.

Response:

Other than the issues addressed in our letter of September 2, 2010 we do not foresee any additional changes to our application.

Ontario Energy Board Interrogatory # 2

In the Board's July 28, 2009 report, under IFRS gains and losses on early retirement of assets in a pool of like assets would continue to be classified as part of depreciation expense and identified separately for review by the Board in future rate filings. However, in its 2011 Rate Application (section Exhibit 9 Tab 1 Schedule 3.0) the Company requested approval to establish a deferral account for such IFRS gains and losses in as they are not reasonably forecastable. This deferral account would become applicable once the Company adopted IFRS accounting, currently scheduled for January 1st 2010.

However, consistent with the Company's September 2, 2010 letter, and with the exception of depreciation service lives, the Company now expects to retain its legacy CGAAP depreciation and gain/loss accounting practices for 2011.

When it adopts IFRS, Hydro One Brampton will commence depreciation of an asset in the month when the asset is put into service as per IAS16 (55) (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). The impact of returning to use of the half year rule for calculating depreciation expense for all USoA accounts in 2011 was calculated and addressed in our September 2nd letter

Ontario Energy Board Interrogatory # 3

Ref: Exhibit 2 / Tab 2/ Schedule 1 – Continuity Statement

In the Fixed Asset Continuity Schedules Forecasts 2010 and 2011, it appears that the Opening Balances for 2010 have been restated. Please explain why the Opening Balances have been restated and the methodology used

Response:

Exhibit 2 Tab 2, Schedule 1 reflected only the Accumulated Amortization relating to 2010 as the Company had restated the opening balance in all capital work accounts based on net book value (NBV) at January 1, 2010. The tables have now been amended so that actual capital additions and Accumulated Amortization are represented instead of NBV. The tables have also been amended to reflect the half year rule for current year additions as discussed in our letter of September 2nd as well as the use of current OEB approved useful lives for 2010.

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Table 1: Forecast Fixed Asset Continuity Schedule 2010:

			Cost					Accumulated Depreciation					
OEB	Account description	Depreciation Rate	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Net Book Value
1805	Land	-	8,146,892	-	-	-	8,146,892	-	-	-	-	-	8,146,892
1806	Land Rights	various	1,412,508	383,000	-	(33,300)	1,762,208	(220,964)	(4,523)	-	-	(225,487)	1,536,720
1808	Buildings and Fixtures	various	29,478,774	435,898	-		29,914,672	(8,556,449)	(591,106)	-	-	(9,147,555)	20,767,117
1815	Transformer Station Equipment - Normally Primary above 50 kV	various	12,011,917	814,102	-	(154,746)	12,671,273	(2,112,335)	(395,503)	-	-	(2,507,838)	10,163,435
1820	Distribution Station Equipment - Normally Primary below 50 kV	various	40,492,279	1,222,000	-	(105,400)	41,608,879	(27,932,761)	(1,355,438)	-	-	(29,288,199)	12,320,680
1830	Poles, Towers and Fixtures	25	61,098,800	7,455,828	-	(743,292)	67,811,336	(21,713,492)	(2,396,131)	-	-	(24,109,623)	43,701,713
1835	Overhead Conductors and Devices	25	19,376,229	1,988,000	-	(197,165)	21,167,064	(3,732,776)	(795,913)	-	-	(4,528,689)	16,638,375
1840	Underground Conduit	25	17,738,414	3,441,345	-	(342,664)	20,837,095	(2,494,932)	(740,536)	-	-	(3,235,468)	17,601,627
1845	Underground Conductors and Devices	25	215,034,537	11,303,857	-	(1,124,981)	225,213,413	(94,946,248)	(8,268,775)	-	-	(103,215,023)	121,998,389
1850	Line Transformers	25	88,592,205	4,860,014	-	(483,452)	92,968,767	(43,851,426)	(3,195,173)	-	-	(47,046,600)	45,922,168
1855	Services	25	23,014,363	661,552	-	-	23,675,915	(11,908,672)	(892,740)	-	-	(12,801,411)	10,874,504
1860	Meters	various	43,203,730	1,026,750	-	-	44,230,480	(15,045,559)	(1,720,674)	-	(325,000)	(17,091,233)	27,139,247
1908	Buildings and Fixtures	25	310,348	-	-	-	310,348	(33,853)	(12,289)	-	-	(46,141)	264,207
1915	Office Furniture and Equipment	10	1,702,247	528,000	-	-	2,230,247	(1,581,833)	(63,118)	-	-	(1,644,951)	585,295
1920	Computer Equipment - Hardware	5	3,199,798	840,400	-	-	4,040,198	(2,846,894)	(265,618)	-	-	(3,112,511)	927,687
1925	Computer Software	5	-	-	-	-	-	-	-	-	-	-	-
1930	Transportation Equipment	various	9,376,602	1,980,000	-	-	11,356,602	(5,981,990)	(704,519)	-	-	(6,686,509)	4,670,092
1935	Stores Equipment	10	219,670	-	-	-	219,670	(120,212)	(16,339)	-	-	(136,551)	83,119
1940	Tools, Shop and Garage Equipment	10	2,847,869	381,000	-	-	3,228,869	(1,999,230)	(159,804)	-	-	(2,159,034)	1,069,835
1950	Power Operated Equipment	8	37,250	-	-	-	37,250	(24,835)	(4,486)	-	-	(29,321)	7,929
1955	Communication Equipment	10	605,068	41,600	-	-	646,668	(183,893)	(62,587)	-	-	(246,479)	400,188
1960	Miscellaneous Equipment	10	140,957	-	-	-	140,957	(58,716)	(14,098)	-	-	(72,814)	68,142
1980	System Supervisory Equipment	15	4,511,464	101,000	-	-	4,612,464	(3,219,842)	(191,915)	-	-	(3,411,756)	1,200,708
1995	Contributions and Grants - Credit	25	(100,287,257)	(11,627,427)	-	(31,066)	(111,945,750)	17,221,643	3,706,725	-	-	20,928,368	(91,017,383)
			482,264,663	25,836,919	-	(3,216,066)	504,885,516	(231,345,270)	(18,144,560)	-	(325,000)	(249,814,830)	255,070,686
2055	Construction Work in Progress--Electric	none	798,274	-	-	3,216,066	4,014,340	-	-	-	-	-	4,014,340
			483,062,937	25,836,919	-	-	508,899,856	(231,345,270)	(18,144,560)	-	(325,000)	(249,814,830)	259,085,026
2040	Electric Plant Held for Future Use	None	3,369,797	-	-	-	3,369,797	-	-	-	-	-	3,369,797
1610	Miscellaneous Intangible Plant - TS CIP	none	5,118,257		-	(5,118,257)	-	-		-	-	-	-
1610	Miscellaneous Intangible Plant - Software CIP	none	84,843	-	-	(84,843)	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - TS in-service	various	3,045,640	5,268,063	-	5,118,257	13,431,960	(117,463)	(204,165)	-	-	(321,627)	13,110,333
1610	Miscellaneous Intangible Plant - Software in-service	various	1,940,555	961,600	-	84,843	2,986,998	(1,249,045)	(285,563)	-	-	(1,534,608)	1,452,390
			10,189,295	6,229,663	-	0	16,418,958	(1,366,507)	(489,728)	-	-	(1,856,235)	14,562,722
	Total		496,622,029	32,066,582	-	0	528,688,611	(232,711,777)	(18,634,288)	-	(325,000)	(251,671,065)	277,017,545

Table 2: Forecast Fixed Asset Continuity Schedule 2011:

			Cost					Accumulated Depreciation					
OEB	Account description	Depreciation Rate	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Net Book Value
1805	Land	-	8,146,892	-	-	-	8,146,892	-	-	-	-	-	8,146,892
1806	Land Rights	various	1,762,208	192,000	-	16,600	1,970,808	(225,487)	(10,106)	-	-	(235,593)	1,735,214
1808	Buildings and Fixtures	50	29,914,672	970,650	-	(45,127)	30,840,195	(9,147,555)	(613,562)	-	-	(9,761,118)	21,079,077
1815	Transformer Station Equipment - Normally Primary above 50 kV	40	12,671,273	1,643,000	-	23,324	14,337,597	(2,507,838)	(447,576)	-	-	(2,955,414)	11,382,183
1820	Distribution Station Equipment - Normally Primary below 50 kV	40	41,608,879	913,000	-	58,404	42,580,283	(29,288,199)	(582,974)	-	-	(29,871,173)	12,709,110
1830	Poles, Towers and Fixtures	42	67,811,336	5,268,405	-	435,436	73,515,177	(24,109,623)	(1,298,927)	-	-	(25,408,551)	48,106,626
1835	Overhead Conductors and Devices	50	21,167,064	924,000	-	143,069	22,234,133	(4,528,689)	(377,459)	-	-	(4,906,148)	17,327,985
1840	Underground Conduit	50	20,837,095	3,509,502	-	137,548	24,484,145	(3,235,468)	(416,318)	-	-	(3,651,786)	20,832,359
1845	Underground Conductors and Devices	35	225,213,413	13,350,056	-	351,588	238,915,057	(103,215,023)	(5,433,684)	-	-	(108,648,708)	130,266,349
1850	Line Transformers	40	92,968,767	6,123,387	-	129,057	99,221,211	(47,046,600)	(1,589,692)	-	-	(48,636,291)	50,584,920
1855	Services	50	23,675,915	767,000	-	-	24,442,915	(12,801,411)	(282,225)	-	-	(13,083,637)	11,359,278
1860	Meters	15	44,230,480	991,000	-	-	45,221,480	(17,091,233)	(1,761,151)	-	(390,000)	(19,242,383)	25,979,097
1908	Buildings and Fixtures	25	310,348	-	-	-	310,348	(46,141)	(12,289)	-	-	(58,430)	251,918
1915	Office Furniture and Equipment	10	2,230,247	168,475	-	-	2,398,722	(1,644,951)	(97,382)	-	-	(1,742,333)	656,389
1920	Computer Equipment - Hardware	5	4,040,198	305,200	-	-	4,345,398	(3,112,511)	(293,602)	-	-	(3,406,114)	939,284
1925	Computer Software	5	-	-	-	-	-	-	-	-	-	-	-
1930	Transportation Equipment	various	11,356,602	2,294,478	-	-	13,651,080	(6,686,509)	(917,569)	-	-	(7,604,079)	6,047,001
1935	Stores Equipment	10	219,670	-	-	-	219,670	(136,551)	(16,339)	-	-	(152,890)	66,780
1940	Tools, Shop and Garage Equipment	10	3,228,869	104,962	-	-	3,333,831	(2,159,034)	(167,201)	-	-	(2,326,235)	1,007,596
1950	Power Operated Equipment	8	37,250	-	-	-	37,250	(29,321)	(4,486)	-	-	(33,807)	3,443
1955	Communication Equipment	10	646,668	133,400	-	-	780,068	(246,479)	(71,337)	-	-	(317,816)	462,252
1960	Miscellaneous Equipment	10	140,957	-	-	-	140,957	(72,814)	(14,098)	-	-	(86,913)	54,044
1980	System Supervisory Equipment	7	4,612,464	501,000	-	-	5,113,464	(3,411,756)	(683,502)	-	-	(4,095,259)	1,018,205
1995	Contributions and Grants - Credit	35	(111,945,750)	(14,598,572)	-	11,542	(126,532,780)	20,928,368	3,049,765	-	-	23,978,133	(102,554,647)
			504,885,516	23,560,943	-	1,261,441	529,707,900	(249,814,830)	(12,041,713)	-	(390,000)	(262,246,542)	267,461,358
2055	Construction Work in Progress--Electric	None	4,014,340	-	-	(1,261,441)	2,752,899	-	-	-	-	-	2,752,899
			508,899,856	23,560,943	-	-	532,460,799	(249,814,830)	(12,041,713)	-	(390,000)	(262,246,542)	270,214,256
2040	Electric Plant Held for Future Use	None	3,369,797	-	-	-	3,369,797	-	-	-	-	-	3,369,797
1610	Miscellaneous Intangible Plant - TS CIP	None	-	-	-	-	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - Software CIP	None	-	-	-	-	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - TS in-service	various	13,431,960	-	-	-	13,431,960	(321,627)	(332,189)	-	-	(653,816)	12,778,144
1610	Miscellaneous Intangible Plant - Software in-service	5	2,986,998	554,800	-	-	3,541,798	(1,534,608)	(238,810)	-	-	(1,773,418)	1,768,380
			16,418,958	554,800	-	-	16,973,758	(1,856,235)	(570,998)	-	-	(2,427,234)	14,546,524
	Total		528,688,611	24,115,743	-	-	552,804,354	(251,671,065)	(12,612,711)	-	(390,000)	(264,673,776)	288,130,577

Ontario Energy Board Interrogatory # 4

Ref: Exhibit 2 / Tab 4/ Schedule 2 – Working Capital

In Table 1, Working Capital by Account 2006-2011, the Power Purchased for 2010 and 2011 are $272,204,756 and $270,083,728 respectively. These represent approximately an 18% increase as compared to 2009 actual ($229,144,070). Please explain the reason(s) for the increase of the Power Purchased in 2010 and 2011.

Response:

HOBNI confirms that the cost of power increases by approximately 18%. Energy growth accounts for approximately 4% of this and the remaining 14% is attributable to higher commodity pricing. This increase in commodity pricing is mainly attributable to increased Global Adjustment pricing. The effective GA for 2009 was approximately $0.020 per KWH the projected GA for 2010 as per the OEB RPP Pricing report issued April 15. 2010, forecasted GA rate is $0.02772 per KWH

Ontario Energy Board Interrogatory # 5

Ref: Exhibit 2/ Tab 5/ Schedule 7.0 – 2010 Capital Expenditures

On pages 6 it states: "The 2010 budget includes $1,952,709 for the installation of electrical underground distribution facilities for new Developments within the City of Brampton inclusive of a contributed capital component from developers. City of Brampton projections for new residential lots in 2010 total 4000 units."

a) Please provide the number of units, of the total 4000 units, that have already been connected to Hydro One Brampton's distribution system.

Response:

From January 2010 to August 2010 – HOBNI has connected 1875 residential lots. Please note that the connection of a new residential lot does not equate directly to connecting the same number of new customers.

The 4,000 unit estimate is based on Draft Plan application submissions from various developers within the City of Brampton. HOBNI's capital expenditures are based on providing service to all planned lots as indicated in these applications. The number of units forecasted is dependent on the number of lots that the developers expect to have ready for servicing. As can be expected, the developers forecasts can be optimistic. Please see the table below that identifies the planned connections as compared to the actual number of customer connections. HOBNI has an obligation to ensure that there are connection facilities available to service all planned connections.

A serviced lot is not considered a customer until a residential unit is constructed on it and thus, a serviced or connected lot does not equate to a customer. Based on our historical data on average 38% of the planned lots do not get connected in any given year. In addition, data in the Variance column indicates that the actual number of units actually connected has been declining over the past several years.

Hydro One Brampton Networks Inc
Number of Subdivision Connections
2005 - 2009

	Planned Connections	Customer Connections	Variance		
2005	9000	5217	-42.0%	Average Variance Last 5 Years	-38.2%
2006	4600	3989	-13.3%		
2007	7400	5426	-26.7%		
2008	5700	3371	-40.9%		
2009	4100	1297	-68.4%		

b) For the remaining units that have not been connected to Hydro One Brampton's distribution system, please indicate the month and year of the expected completion of the connection.

Response:

It is anticipated that all lots will be serviced in 2010. As per the above, it is not expected that all of these lots will have a residential dwelling installed in it by the end of the year

c) Please identify the total capital contributions received by Hydro One Brampton reflected in the 2010 capital budget.

Response:

Please refer to Table 1, Exhibit 2, Tab 5, Schedule 7.1, Page 1 of 1, Contribution and Grants column.

Ontario Energy Board Interrogatory # 6

Ref: Exhibit 2/ Tab 5/ Schedule 8.0 – 2011 Capital Expenditures

On pages 17 it states: "The 2011 budget is based on City of Brampton projections for the connection of 4,500 residential services in 2011. This work includes the installation of underground electrical distribution facilities for new developments within the city, inclusive of a contributed capital component from Developers."

a) Please advise whether all 4,500 units would be connected to Hydro One Brampton's distribution system by the end of 2011.

Response:

It is anticipated that all services will be connected in 2011. It is important to note that that the connection of a service does not imply that a new customer has been added to the system. It is not uncommon for a lot to be serviced and not have a residential dwelling erected on it for some time. The connection of serviced lots should not be incorporated to mean that this is also the number of new customers to be added to the system

b) If the answer in (a) is negative, please provide the forecasted completion date of the connection of the 4,500 residential units in 2011.

Response:

Hydro One Brampton anticipates connection of 4500 units in 2011.

Ontario Energy Board Interrogatory # 7

Ref: Exhibit 2/ Tab 5/ Schedule 8.0 – 2011 Fleet Maintenance

On pages 18, it states: "The replacement of one V76, a 1992, 19-year old single bucket truck with high mileage and age, by a new 55 ft single bucket truck;….." In reference to Exhibit 2/ Tab 6 / Schedule 1.1/ Appendix E, Hydro One Brampton filed a Fleet Assessment to outline the condition of Hydro One Brampton's fleet. Staff could not identify the fleet condition for V76 in the Fleet Assessment report. Please provide the condition, replacement schedule and replacement value for the V76.

Response:

Truck V76 was not included in the Fleet Assessment because at the time of the assessment it had already been taken out of service and was scheduled for retirement. After the Fleet Assessment was conducted, an evaluation was done on both Truck V73 and V76, as the assessment had shown that V73 required major engine repairs. The decision was made to sell V73 at auction and delay the sale of V76. Note V73 and V76 have the same replacement value of $423,000

Ontario Energy Board Interrogatory # 8

Ref: Exhibit 2/ Tab 5/ Schedule 8.2 – 2011 Fleet Maintenance

On page 86 the proposed business case indicated the costs for One Double Bucket Truck is $773,000. And this truck is scheduled to replace a 1993 unit. In reference to Exhibit 2/ Tab 6 / Schedule 1.1/ Appendix E, Hydro One Brampton filed a Fleet Assessment to outline the condition of Hydro One Brampton's fleet. The report provided the market value for #79, 1993 INT, Double Buckets was $588,640. Please explain the difference of the values for the Double Bucket Truck.

Response:

NOTE: Exhibit 2, Tab 6, Schedule 1.1 Appendix E, page 6 was mislabeled; it should read "Hydro One Brampton Fleet Replacement Schedule"

Please see attached the revised Business case for the Double Bucket Truck in the amount of $633,349.

The business case containing the $773,000 amount was incorrect. The value of $633,349 was included in HOBNI's 2010 Fleet Budget and subsequently flowed through to the General Ledger and the Capital Expenditures table correctly.

The variance between the $633,349 and the amount in Exhibit 2 Tab 6 Schedule 1.1 Appendix E of $588,640 is as a result of the planned plug in Hybrid technology due to green energy incentives, as well as accommodating the increase in reach from 70 ft. to 83 ft. due to changes in pole height standards.

Hydro One Brampton Networks Inc.
Proposed Business Case - Capital Expenditure
For Year 2011

Project Title:	One Double Bucket Truck	**Project Number:**	2011-012
Project Manager:	Brian Oakley	**Project Technician:**	Paul Morin
Last Updated:	23/04/2010	**Investment Category:**	Operations
Type	FL - Fleet	**Investment Driver:**	Safety

Description

One Double Bucket Truck for lines Department

Investment Scope

Investment Results

New reliable vehicle with better safety features

Cost & Timing

	2010	2011	2012	2013	2014
Capital Costs		**$633,349.00**			
OM&A					
Gross		**$633,349.00**			
Recoverable					
Net Investment		**$633,349.00**			

Project Start Date	**January**
Project In-Service Date	**November**

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Business Case Justification
New Double bucket truck scheduled to replace a 1993 unit.
Alternatives Considered
longer reach for higher pole lines

Ontario Energy Board Interrogatory # 9

Ref: Exhibit 2/ Tab 5/ Schedule 8.0 – 2011 Fleet Maintenance

On pages 18-19, it states: "The replacement of V09, a 1999, 12-year old compact car, by a vehicle with better safety features and more reliability;….." In reference to Exhibit 2/ Tab 6 / Schedule 1.1/ Appendix E, Hydro One Brampton filed a Fleet Assessment to outline the condition of Hydro One Brampton's fleet. The report however commented that "Many of cars in the pool fleet have low kilometers for their age. I have included these in the replacement schedule but would suggest decreasing the size of this car fleet and renting as needed for students etc.

These vehicles are parked for considerable time during the year, which creates rust in exhaust and brakes, and require unnecessary maintenance due to outside storage."

a) Based on the comment from the report, has Hydro One Brampton considered renting instead of purchasing?

Response:

Yes. In the summer of 2010, HOBNI awarded a rental agreement based on a tendering process involving three bidders. The tender was awarded to the lowest bidder.

b) According to the Fleet Assessment report, car #9, 1999 Escort, scheduled to be replaced in 2012. Please explain why Hydro One Brampton proposes to replace it in 2011.

Response:

Car # 9 was assessed as requiring major maintenance and repairs thus the decision was made to replace Car# 9 and delay the replacement of Car #5.

Ontario Energy Board Interrogatory # 10

Ref: Exhibit 2/ Tab 5/ Schedule 1.0 – Capital Expenditures

On page 2, Table 1 provides capital expenditures for the period from 2006 to 2011 based on IFRS.

a) Please use the same format as Table 1 to provide the expenditures based on CGAAP.

Response:

Exhibit 2, Tab 5, Schedule 1, Table 1 based on CGAAP is shown below:

OEB #	Description	2006	2007	2008	2009	2010	2011
1805	Land	-	-	-	-	-	-
1806	Land Rights	58,458	19,170	7,069	23,226	349,700	208,600
1808	Buildings and Fixtures	1,123,351	1,630,659	1,283,556	602,472	4,663,780	925,523
1815	Transformer Station Equipment - Normally Primary above 50 kV	3,474	12,600	3,803,296	257,953	(3,568,526)	1,666,324
1820	Distribution Station Equipment - Normally Primary below 50 kV	639,781	192,033	169,870	279,295	1,116,601	971,404
1830	Poles, Towers and Fixtures	5,802,455	5,777,486	4,388,180	7,129,091	6,712,536	5,703,841
1835	Overhead Conductors and Devices	2,191,510	1,983,311	2,073,555	2,214,142	1,790,835	1,067,069
1840	Underground Conduit	2,284,568	2,102,665	1,926,785	4,665,139	3,098,681	3,647,050
1845	Underground Conductors and Devices	6,352,682	23,445,365	16,144,870	7,731,744	10,178,876	13,701,644
1850	Line Transformers	3,160,025	2,278,674	5,378,129	6,208,233	4,376,562	6,252,444
1855	Services	714,723	793,538	544,543	613,536	661,552	767,000
1860	Meters	1,170,387	6,157,185	6,392,693	9,445,080	1,026,415	991,000
1908	Buildings and Fixtures	-	-	-	-	(0)	-
1915	Office Furniture and Equipment	47,337	86,526	84,367	2,570	528,000	168,475
1920	Computer Equipment - Hardware	453,294	476,458	155,453	70,653	840,400	305,200
1925	Computer Software	226,383	508,907	184,032	-	-	-
1930	Transportation Equipment	714,607	1,355,127	90,483	215,003	1,979,999	2,294,478
1935	Stores Equipment	19,150	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	152,979	287,536	156,761	159,036	381,000	104,962
1950	Power Operated Equipment	-	-	-	-	-	-
1955	Communication Equipment	50,146	102,028	78,757	117,318	41,600	133,400
1960	Miscellaneous Equipment	16,025	15,620	12,711	8,554	-	-
1980	System Supervisory Equipment	195,795	208,555	144,806	64,979	101,000	501,000
1995	Contributions and Grants - Credit	(4,471,257)	(18,528,211)	(16,082,800)	(12,704,438)	(11,658,493)	(14,587,030)
2055	Construction Work in Progress--Electric	682,425	1,964,208	(1,397,746)	798,274	3,216,066	(1,261,441)
2040	Electric Plant Held for Future Use	-	-	3,554,454	258,332	-	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	5,118,257	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	84,843	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	(130,042)	5,268,063	-
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	61,000	961,600	554,800
	Total	**21,588,299**	**30,869,441**	**29,093,824**	**33,294,250**	**32,066,248**	**24,115,743**

b) Please use the same format as Table 1 to provide the expenditures based on CGAAP and exclude Smart Meter related costs.

Response:

Exhibit 2, Tab 5, Schedule 1, Table 1 based on CGAAP excluding Smart Meter costs is shown below:

OEB #	Description	2006	2007	2008	2009	2010	2011
1805	Land	-	-	-	-	-	-
1806	Land Rights	58,458	19,170	7,069	23,226	349,700	208,600
1808	Buildings and Fixtures	1,123,351	1,630,659	1,283,556	602,472	4,663,780	925,523
1815	Transformer Station Equipment - Normally Primary above 50 kV	3,474	12,600	3,803,296	257,953	(3,568,526)	1,666,324
1820	Distribution Station Equipment - Normally Primary below 50 kV	639,781	192,033	169,870	279,295	1,116,601	971,404
1830	Poles, Towers and Fixtures	5,802,455	5,777,486	4,388,180	7,129,091	6,712,536	5,703,841
1835	Overhead Conductors and Devices	2,191,510	1,983,311	2,073,555	2,214,142	1,790,835	1,067,069
1840	Underground Conduit	2,284,568	2,102,665	1,926,785	4,665,139	3,098,681	3,647,050
1845	Underground Conductors and Devices	6,352,682	23,445,365	16,144,870	7,731,744	10,178,876	13,701,644
1850	Line Transformers	3,160,025	2,278,674	5,378,129	6,208,233	4,376,562	6,252,444
1855	Services	714,723	793,538	544,543	613,536	661,552	767,000
1860	Meters	1,105,012	910,865	484,492	782,066	1,026,415	991,000
1908	Buildings and Fixtures	-	-	-	-	(0)	-
1915	Office Furniture and Equipment	47,337	86,526	84,367	2,570	528,000	168,475
1920	Computer Equipment - Hardware	453,294	476,458	155,453	70,653	840,400	305,200
1925	Computer Software	226,383	508,907	184,032	-	-	-
1930	Transportation Equipment	714,607	1,355,127	90,483	215,003	1,979,999	2,294,478
1935	Stores Equipment	19,150	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	152,979	287,536	156,761	159,036	381,000	104,962
1950	Power Operated Equipment	-	-	-	-	-	-
1955	Communication Equipment	50,146	102,028	78,757	117,318	41,600	133,400
1960	Miscellaneous Equipment	16,025	15,620	12,711	8,554	-	-
1980	System Supervisory Equipment	195,795	208,555	144,806	64,979	101,000	501,000
1995	Contributions and Grants - Credit	(4,471,257)	(18,528,211)	(16,082,800)	(12,704,438)	(11,658,493)	(14,587,030)
2055	Construction Work in Progress--Electric	682,425	1,964,208	(1,397,746)	798,274	3,216,066	(1,261,441)
2040	Electric Plant Held for Future Use	-	-	3,554,454	258,332	-	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	5,118,257	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	84,843	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	(130,042)	5,268,063	-
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	61,000	961,600	554,800
	Total	**21,522,924**	**25,623,120**	**23,185,623**	**24,631,236**	**32,066,248**	**24,115,743**

c) In the bottom of Table 1, there is a note stating: "Above Capital Expenditures exclude $300,000 of borrowing costs which are included in the total in Exhibit 2, Tab 6, Schedule 9." Please explain what type of borrowing costs this statement is referring to.

Response:

The note at the bottom of Table 1 should have read as follows: "Above Capital Expenditures include $300,000 of borrowing costs." The reference to Exhibit 2, Tab 6, Schedule 9 should not have been made

Ontario Energy Board Interrogatory # 11

Ref: Exhibit 2/ Tab 6/ Schedule 1.1/ Appendix E – Asset Management Plan

On page 12 & 13 of its Asset Management Plan, Hydro One Brampton provides the Demand and Energy forecast for the period from 2010 – 2019. Tables 2 and 3 are not readable from the evidence. Please re-produce Tables 2 and 3.

Response:

Tables 2 and 3 are provided below..

HYDRO ONE BRAMPTON DEMAND FORECAST 2010- 2019

	ACTUAL MEGAWATT PEAK								PROJECTED MEGAWATT PEAK									
MTH.	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
JAN	500.7	546.3	561.5	574.5	569.8	618.0	591.3	598.1	600.0	613.8	627.9	642.4	657.1	672.2	687.7	703.5	719.7	736.3
FEB	505.6	527.7	530.0	542.8	560.5	602.0	596.6	584.4	600.0	613.8	627.9	642.4	657.1	672.2	687.7	703.5	719.7	736.3
MAR	491.5	517.5	523.0	544.5	551.1	579.3	563.5	577.5	586.0	599.5	613.3	627.4	641.8	656.6	671.7	687.1	702.9	719.1
APR	485.2	491.4	496.4	480.6	507.8	522.8	525.7	513.4	525.0	537.1	549.4	562.1	575.0	588.2	601.7	615.6	629.7	644.2
MAY	502.6	451.0	543.8	485.1	723.3	633.0	518.2	504.4	590.0	603.6	617.5	631.7	646.2	661.0	676.2	691.8	707.7	724.0
JUN	617.1	661.8	628.3	731.2	670.6	772.1	729.2	691.5	740.0	757.0	774.4	792.2	810.5	829.1	848.2	867.7	887.6	908.1
JUL	655.7	637.7	645.9	724.0	755.0	749.5	720.0	592.1	750.0	767.3	784.9	802.9	821.4	840.3	859.6	879.4	899.6	920.3
AUG	642.1	622.2	620.7	707.7	784.9	755.6	674.1	736.8	760.0	777.5	795.4	813.7	832.4	851.5	871.1	891.1	911.6	932.6
SEP	644.0	506.7	564.7	641.6	546.2	704.6	694.4	575.0	630.0	644.5	659.3	674.5	690.0	705.9	722.1	738.7	755.7	773.1
OCT	527.7	477.4	500.9	563.8	528.5	537.0	546.7	545.0	550.0	562.7	575.6	588.8	602.4	616.2	630.4	644.9	659.7	674.9
NOV	497.0	507.7	535.7	566.4	551.7	583.0	572.2	580.0	590.0	603.6	617.5	631.7	646.2	661.0	676.2	691.8	707.7	724.0
DEC	539.7	531.0	578.9	593.4	586.9	595.2	594.0	600.0	605.0	618.9	633.2	647.7	662.6	677.8	693.4	709.4	725.7	742.4
AVG.	550.7	538.9	560.8	596.3	611.4	637.7	610.5	590.5	627.2	641.6	656.3	671.4	686.9	702.7	718.8	735.4	752.3	769.6
% GROWTH		-2.0	3.9	6.3	2.5	4.3	-4.3	-3.3	6.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
SUMMER	655.7	661.8	645.9	731.2	784.9	772.1	729.2	736.8	760.0	777.5	795.4	813.7	832.4	851.5	871.1	891.1	911.6	932.6
% GROWTH		0.9	-2.4	13.2	7.3	-1.6	-5.8	1.0	3.1	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
WINTER P	539.7	546.3	578.9	593.4	586.9	618.0	596.6	600.0	605.0	618.9	633.2	647.7	662.6	677.8	693.4	709.4	725.7	742.4
% GROWTH		1.2	6.0	2.5	-1.1	5.3	-3.5	0.6	0.8	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3

** These values do not consider the 5 megawatts of generation from Maple Lodge Farms

- numbers in green indicate forecasted values for 2009 & 2010

- yellow background indicates preliminary values not yet confirmed by the IESO

Table 2

1

HYDRO ONE BRAMPTON ENERGY FORECAST 2010- 2019

	ACTUAL GIGAWATT-HOURS								PROJECTED GIGAWATT-HOURS									
MTH.	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
JAN	284.4	307.2	318.3	328.6	327.5	331.9	343.3	341.4	345.0	352.9	361.1	369.4	377.9	386.5	395.4	404.5	413.8	423.4
FEB	261.0	276.5	291.1	292.2	303.2	317.8	324.9	299.8	317.0	324.3	331.7	339.4	347.2	355.2	363.3	371.7	380.2	389.0
MAR	280.2	291.2	303.9	312.7	323.6	328.3	329.4	319.2	330.0	337.6	345.4	353.3	361.4	369.7	378.2	386.9	395.8	404.9
APR	266.4	267.8	278.7	284.2	287.0	300.2	300.8	286.5	297.0	303.8	310.8	318.0	325.3	332.8	340.4	348.2	356.3	364.4
MAY	265.7	265.7	282.2	285.9	307.7	314.7	299.5	279.5	300.0	306.9	314.0	321.2	328.6	336.1	343.9	351.8	359.9	368.1
JUN	286.1	286.3	291.6	353.6	331.9	351.0	335.2	302.3	340.0	347.8	355.8	364.0	372.4	380.9	389.7	398.7	407.8	417.2
JUL	334.6	314.6	312.9	365.3	370.3	349.2	363.3	312.9	355.0	363.2	371.5	380.1	388.8	397.7	406.9	416.3	425.8	435.6
AUG	320.6	296.9	312.5	368.0	353.8	361.5	341.4	343.1	355.0	363.2	371.5	380.1	388.8	397.7	406.9	416.3	425.8	435.6
SEP	286.8	265.0	298.2	312.6	297.8	318.2	317.9	310.0	320.0	327.4	334.9	342.6	350.5	358.5	366.8	375.2	383.8	392.7
OCT	272.7	271.5	286.9	303.7	307.7	316.4	311.1	315.0	317.0	324.3	331.7	339.4	347.2	355.2	363.3	371.7	380.2	389.0
NOV	276.1	279.4	295.3	307.4	313.4	321.8	314.8	316.0	323.0	330.4	338.0	345.8	353.8	361.9	370.2	378.7	387.4	396.4
DEC	290.8	293.1	314.2	327.6	316.4	331.5	329.8	325.0	333.0	340.7	348.5	356.5	364.7	373.1	381.7	390.5	399.4	408.6
AVG.	285.5	284.7	298.8	319.3	320.0	328.5	326.0	312.7	327.7	335.2	342.9	350.8	358.9	367.1	375.6	384.2	393.0	402.1
% AVG. GROWTH		-0.3	5.0	6.9	0.2	2.7	-0.8	-4.1	4.8	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3

- numbers in green indicate forecasted values for 2009 & 2010

- yellow background indicates preliminary values not yet confirmed by the IESO

Table 3

1
2

Ontario Energy Board Interrogatory # 12

12. Ref: Exhibit 3 / Tab 2/ Schedule 2.0/ page 3 – Load Forecasting assumption

On page 3, it states: "The annual CDM impact for 2010-2012 submitted in the IPSP by the OPA to the Ontario Energy Board in August 2007 was adjusted to account for the recent economic recession and its impact on industrial customers and the new CDM target for LDCs for the 2011-2014 period. Table 1 summarizes the adjusted annual provincial CDM impact assumed by Hydro One Brampton for 2008-2012."

Table 1: Provincial CDM Impact (in GWh)

Provincial CDM Impact (In GWh)

	Provincial CDM Impact Assumed in 2007 IPSP		Provincial CDM Impact Assumed in this Rate Case	
	Incremental	Cumulative since 2006	Incremental	Cumulative since 2006
2008	814	814	814	814
2009	1,146	1,960	1,146	1,960
2010	4,908	6,868	3,416	5,376
2011	1,885	8,753	2,386	7,762
2012	1,909	10,662	2,900	10,662

Note 1: CDM impact is presented at generation station level, weather normal

Note 2: Cumulative CDM impact of 10,662 GWh remains the same by 2012

a) Hydro One Brampton explained that the CDM impact accounted for the recent economic recession and its impact on industrial customers. Please explain the reason(s) for the increase of the incremental CDM impact from 1,885 to 2,386 GWh in 2011 and from 1,909 to 2,900 GWh in 2012.

Response:

In view of the recent economic recession, it was a forecast judgment of postponing 1,492 GWh of CDM impact from 2010 to 2011 and 2012. This is the reason for the CDM impact to increase from 1,885 GWh to 2,386 GWh in 2011 and from 1,909 GWh to 2,900 GWh in 2012. As shown in Table 1, Hydro One Brampton uses the same cumulative CDM impacts of 10,662 GWh for 2008-2012 assumed by the OPA consistent with the IPSP submitted to the Board in August 2007.

b) Please provide the details on how Hydro One Brampton is planning to achieve the incremental CDM target as stated in Table 1 for 2010, 2011, and 2012.

Response:

Hydro One Brampton is planning on achieving the incremental CDM targets for 2010 as defined by the OPA, by delivering the suite of programs presently being offered by the OPA. These include the Electricity Retrofit Incentive Program, the Peak Saver Program (ERIP), The Appliance Retirement Program (Great Refrigerator Round Up) and the Small Commercial Direct Install Program (Power Blitz). Hydro One Brampton has also partnered up with Greensavers to offer the Multi-unit Energy Efficiency Retrofit Program (MEER). For 2011 and 2012 Hydro One Brampton will once again deliver to its customers the full suite of programs currently being developed and launched by the OPA. It has been accepted that the OPA programs alone will not be sufficient to reach provincial targets. Hydro One has been working with the OPA, EDA, and other distributors to develop Tier 2 programs that will assist LDC's in meeting the set targets. These Tier 2 programs will augment the Tier 1 programs and will ensure that targets are met for all market segments.

Ontario Energy Board Interrogatory # 13

Ref: Exhibit 3/ Tab 2/ Schedule 3.0 – Load Forecast

On pages 3, it states: "Historic and forecast population data for the city of Brampton was taken from the City of Brampton's planning report as published in April of 2009." Please file the City of Brampton's planning report identified above.

Response:

Please see **Appendix L**

Ontario Energy Board Interrogatory # 14

Ref: Exhibit 3/ Tab 2/ Schedule 3.0 – Load Forecast

On pages 5, it states: "The weather normalized quantities for the Bridge and Test Years is determined by using 2010 and 2011 independent variables in the prediction formula on a monthly basis along with the average monthly heating degree days and cooling degree days which has occurred from January 2003 to December 2009."

Using a similar method to develop the weather normalized forecast for 2010 and 2011, please provide the following scenarios.

a) Instead of using the average monthly heating degree days (HDD) and cooling degree days (CDD) from 2003 to 2009, please develop the weather normalized forecast for 2010 and 2011 by using average monthly HDD and CDD from 2000 to 2009. Please calculate the variance and percent variance from the 2010 and 2011 proposed weather normalized forecast.

Response:

Hydro One Brampton would like to clarify that the submitted model was populated with the 30 year averages of HDD and CDD and not the average from 2003 through 2009.

As requested Hydro One Brampton has run the regression using the average HDD and CDD for 2000 through 2009. The results of the requested change are as follows:

	2010 Original	2010 Revised	Variance		2011 Original	2011 Revised	Variance
Purchased kWh	3,821,797,458	3,838,280,218	0.43%		3,898,527,442	3,915,010,202	0.42%
Billed kWh	3,698,071,300	3,714,020,451	0.43%		3,772,317,241	3,788,266,392	0.42%

b) Instead of using the average monthly heating degree days (HDD) and cooling degree days (CDD) from 2003 to 2009, please develop the weather normalized forecast for 2010 and 2011 by using a trend of monthly HDD and CDD from 2000 to 2009. Please calculate the variance and percent variance from the 2010 and 2011 proposed weather normalized forecast.

Response:

Hydro One Brampton would like to clarify that the submitted model was populated with the 30 year averages of HDD and CDD and not the average from 2003 through 2009.

As requested Hydro One Brampton has run the regression using the trend of HDD and CDD for 2000 through 2009 as opposed to using the 30 year average. The results of this change are as follows:

	2010 Original	2010 Revised	Variance		2011 Original	2011 Revised	Variance
Purchased kWh	3,821,797,458	3,822,073,518	0.01%		3,898,527,442	3,868,961,879	(0.76%)
Billed kWh	3,698,071,300	3,698,338,423	0.01%		3,772,317,241	3,743,708,829	(0.76%)

Hydro One Brampton would like to note that the variance between the two forecasts is very small; especially in 2010, however, Hydro One Brampton recommends against using the trend approach to estimate HDD and CDD for the years 2010 and 2011. Since HDD and CDD have been declining over the last several years of this data selection, using a linear trend to forecast those

degree days implies that they will reach and surpass 0, entering into the negatives, which is of course impossible. Already the trending approach estimated a value of -0.26 for April 2010. Hydro One Brampton believes that using the 30 year average is a much more appropriate approach.

Ontario Energy Board Interrogatory # 15

Ref: Exhibit 3 / Tab 4 / Schedule 1.1 / Page 1 – Interest and Dividend Income

Please provide a breakdown of the interest income for 2008, 2009, 2010 and 2011 that is related to:

I. Monthly interest earned in the bank account

II. Interest on Regulatory assets/ Liabilities

III. Interest earned on loans Hydro One Brampton has made to its affiliate businesses

IV. All other sources.

Response:

The breakdown of interest income for 2008, 2009, 2010 and 2011 is shown below:

	2008	2009	2010	2011
I. Monthly interest earned in the bank account	321,978	20,174	6,680	2,799
II. Interest on Regulatory assets/ Liabilities	-	-	-	-
III. Interest earned on loans Hydro One Brampton has made to its affiliate businesses			-	-
IV. All other sources.	450	6,629	-	-
	$ 322,429	**$ 26,803**	**$ 6,680**	**$ 2,799**

Ontario Energy Board Interrogatory # 16

Ref: Exhibit 4 / Tab 2 / Schedule 1.1 – Summary of OM&A Expenses

On Page 1, Table 1 provides a summary of OM&A expenses for the period from 2006 to 2011.

a) Please use the same format as shown in Table 1 to provide the OM&A expenses based on CGAAP.

Response:

Exhibit 4, Tab 2, Schedule 1.1, Table 1 is revised and shown below based on CGAAP::

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year (BY) 2010	Variance BY 2010 - 2009 Actuals	Test Year (TY) 2011	Variance TY - BY
Operation	2,720,134	3,350,836	630,702	3,079,156	(271,680)	3,544,751	465,594	3,815,041	270,290	4,900,708	1,085,667	4,559,988	(340,720)
Maintenance	2,700,089	3,023,980	323,891	3,091,210	67,230	3,374,105	282,895	3,159,226	(214,879)	3,590,436	431,210	3,904,606	314,170
Billing and Collecting	3,512,796	3,775,564	262,768	3,820,263	44,699	4,324,468	504,205	4,897,921	573,454	4,632,782	(265,139)	5,656,663	1,023,881
Community Relations	256,376	1,018,450	762,075	797,999	(220,451)	371,587	(426,412)	363,138	(8,449)	570,000	206,862	640,000	70,000
Administrative and General	4,463,821	4,986,820	522,999	5,137,182	150,361	5,558,770	421,588	5,601,103	42,334	6,699,374	1,098,271	7,445,278	745,904
Total OM&A Expenses	13,653,216	16,155,651		15,925,811		17,173,680		17,836,429		20,393,300		22,206,535	
Variance from previous year			2,502,435		(229,840)		1,247,870		662,748		2,556,871		1,813,235
Percent change (year over year)			18.33%		-1.42%		7.84%		3.86%		14.34%		8.89%
Percent change: Test year vs Most Current Actuals		24.50%											
Average for 2006-2009		7.15%											
Compound Annual Growth Rate (for 2006 to 2009)		1.74%											

b) Please use the same format as shown in Table 1 to provide the OM&A expenses based on CGAAP and exclude Smart Meter related costs.

Response:

There were no smart meter related costs in historical years and 2010, as those were being deferred on the balance sheet in USoA 1556. In 2011, there are Smart Meter related costs in OM&A.

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year (BY) 2010	Variance BY 2010 - 2009 Actuals	Test Year (TY) 2011	Variance TY - BY
Operation	2,720,134	3,350,836	630,702	3,079,156	(271,680)	3,544,751	465,594	3,815,041	270,290	4,900,708	1,085,667	2,911,549	(1,989,159)
Maintenance	2,700,089	3,023,980	323,891	3,091,210	67,230	3,374,105	282,895	3,159,226	(214,879)	3,590,436	431,210	3,904,606	314,170
Billing and Collecting	3,512,796	3,775,564	262,768	3,820,263	44,699	4,324,468	504,205	4,897,921	573,454	4,632,782	(265,139)	5,656,663	1,023,881
Community Relations	256,376	1,018,450	762,075	797,999	(220,451)	371,587	(426,412)	363,138	(8,449)	570,000	206,862	640,000	70,000
Administrative and General	4,463,821	4,986,820	522,999	5,137,182	150,361	5,558,770	421,588	5,601,103	42,334	6,699,374	1,098,271	7,445,278	745,904
Total OM&A Expenses	13,653,216	16,155,651		15,925,811		17,173,680		17,836,429		20,393,300		20,558,096	
Variance from previous year			2,502,435		(229,840)		1,247,870		662,748		2,556,871		164,796
Percent change (year over year)			18.33%		-1.42%		7.84%		3.86%		14.34%		0.81%
Percent change: Test year vs Most Current Actuals		15.26%											
Average for 2006-2009		7.15%											
Compound Annual Growth Rate (for 2006 to 2009)		1.74%											

Ontario Energy Board Interrogatory # 17

Ref: Exhibit 4 / Tab 2 / Schedule 1.3 / Page 11 – Meter Maintenance

In the above reference provided for the explanation of the cost drivers in relation to 2010 meter maintenance, it states: "The increase is mainly associated with Hydro One Brampton's smart metering program. Throughout the implementation of this program, it was decided to focus on installing meters on customers in the parts of the city that would present the least amount of failed meter bases and failed equipment. All questionable areas, those areas that were expected to have a high failure rate, were postponed and will be completed in 2010. As a result, an additional $400,000 was budgeted to cover off theses costs in 2010. It is also expected that Hydro One Brampton will be paying approximately $320,000 in software costs associated with the smart metering program once the installation project is completed. There were no costs for this in 2009."

However in reference to Exhibit 9/ Tab 3/ Schedule 1.1/ page 6, it states:

"HydroOne Brampton is requesting an ongoing rate funding adder to cover additional investments in Smart Meters in 2010 and 2011 as well as the revenue requirement for the 2010 Bridge Year for investments to the end of 2009."

Please clarify whether the meter maintenance costs in relation to Smart Meters are included in 2010 OM&A or remain recorded in the smart meter deferral account.

Response:

In 2010 and 2011, smart meter maintenance costs for smart meters installed to the end of 2009 are being expensed, while maintenance costs for smart meters installed in 2010 and 2011 will be recorded in the smart meter deferral account for regulatory purposes.

Ontario Energy Board Interrogatory # 18

Ref: Exhibit 4 / Tab 2 / Schedule. 3.0 - Regulatory Costs

On page 2, it states: "Hydro One Brampton is requesting that the total amount associated with the 2011 Cost of Service Rate Application of $70,000 be recovered in one year."

Please provide the rationale for recovering the costs over a one year period.

Response:

HOBNI did not amortize the one-time costs associated with the current cost of service application over two or more years as it was deemed not to be material.

Ontario Energy Board Interrogatory # 19

Ref: Exhibit 4 / Tab 4 / Schedule 1.0 / Page 2 – Average Compensation per FTEE

a) Table 1 indicates that the average compensation per FTEE for 2011 is $94,129. This represents a 4.6% increase as compared to 2010 ($89,948). In reference to Exhibit 4/ Tab 4/ Schedule 3.0/ page 1, Hydro One Brampton projected the base wage adjustment for both Union, and Executive, Management and Non-union staff are 0%. Please explain the reason for the increase in average compensation given the 0% base wage adjustment.

Response:

This schedule has been reissued.

Total Annual Compensation & Average Compensation Per Full Time Employee Equivalent (FTEE)*				
	2006 OEB Approved (Actual)	2009 (Actual)	2010 (Projected)	2011 (Projected)
Executive	413,579	764,414	778,359	788,301
Management	3,021,598	4,451,264	4,637,163	4,695,056
Non-Union	1,171,065	1,734,120	1,947,394	2,081,976
Union	10,596,189	13,323,748	14,393,375	14,855,503
Total Compensation	15,202,431	20,273,546	21,756,291	22,420,836
Number of FTEE's	183	211	225	231
Average Compensation per FTEE	**$83,073**	**$96,083**	**$96,695**	**$97,060**

b) Table 1 indicates that the average compensation per FTEE for 2010 is $89,948. This represents a 1.2% decrease as compared to 2009 ($91,045). In reference to Exhibit 4/ Tab 4/ Schedule 3.0/ page 1, Hydro One Brampton indicated that the base wage adjustment for Union is a 3% increase, and Executive, Management and Non-union staff is an average 2% increase. Please explain this apparent inconsistency.

Response:

This schedule has been reissued.

Total Annual Compensation & Average Compensation Per Full Time Employee Equivalent (FTEE)*				
	2006 OEB Approved (Actual)	2009 (Actual)	2010 (Projected)	2011 (Projected)
Executive	413,579	764,414	778,359	788,301
Management	3,021,598	4,451,264	4,637,163	4,695,056
Non-Union	1,171,065	1,734,120	1,947,394	2,081,976
Union	10,596,189	13,323,748	14,393,375	14,855,503
Total Compensation	15,202,431	20,273,546	21,756,291	22,420,836
Number of FTEE's	183	211	225	231
Average Compensation per FTEE	**$83,073**	**$96,083**	**$96,695**	**$97,060**

Ontario Energy Board Interrogatory # 20

Ref: Exhibit 4 / Tab 4 / Schedule 9.1 / Page 1 – Employee Costs

Please include 2006 actuals, 2007 actuals, and 2008 actuals employee costs and FTEE to Table 1 listed in the above reference.

Response:

This schedule is provided below:

Employee Costs

	Last Rebasing Year (2004)	2006	2007	2008	Historical Year (Bridge Year - 1) (2009)	Bridge Year (2010)	Test Year (2011)
Number of Employees (FTEs including Part-Time)							
Executive	2	2	2	3	3	3	3
Management	27	30	32	33	34	35	35
Non-Union	16	16	21	22	25	28	30
Union	138	144	146	149	149	159	163
Total	183	192	201	207	211	225	231
Number of Part-Time Employees							
Executive	-	-	-	-	-	-	-
Management	-	-	-	-	-	-	-
Non-Union	5	5	6	7	7	7	7
Union	-	-	-	-	-	-	-
Total	5	5	6	7	7	7	7
Total Salary and Wages							
Executive	$ 332,375	$ 365,974	$ 415,026	$ 610,009	$ 599,308	$ 611,294	$ 611,294
Management	$ 2,428,323	$ 2,825,771	$ 3,127,382	$ 3,475,795	$ 3,489,836	$ 3,664,328	$ 3,664,328
Non-Union	$ 941,133	$ 931,035	$ 1,148,006	$ 1,238,373	$ 1,359,568	$ 1,568,398	$ 1,680,426
Union	$ 8,515,684	$ 9,181,446	$ 9,575,375	$ 10,381,430	$ 10,445,953	$ 11,481,434	$ 11,770,275
Total	$ 12,217,515	$ 13,304,226	$ 14,265,789	$ 15,705,607	$ 15,894,665	$ 17,325,454	$ 17,726,324
Current Benefits							
Executive	$ 78,348	$ 88,081	$ 102,832	$ 143,796	$ 155,792	$ 160,466	$ 165,280
Management	$ 572,405	$ 680,091	$ 774,881	$ 819,340	$ 907,197	$ 934,413	$ 962,445
Non-Union	$ 221,844	$ 224,076	$ 284,445	$ 291,918	$ 353,425	$ 364,028	$ 374,949
Union	$ 2,007,319	$ 2,209,741	$ 2,372,518	$ 2,447,187	$ 2,715,467	$ 2,796,931	$ 2,880,839
Total	$ 2,879,916	$ 3,201,989	$ 3,534,676	$ 3,702,241	$ 4,131,881	$ 4,255,837	$ 4,383,513
Accrued Pension and Post-Retirement Benefits							
Executive	$ 2,857	$ 8,720	$ 10,008	$ 15,381	$ 9,313	$ 6,598	$ 11,726
Management	$ 20,870	$ 67,330	$ 75,413	$ 87,638	$ 54,231	$ 38,423	$ 68,283
Non-Union	$ 8,088	$ 22,184	$ 27,683	$ 31,224	$ 21,127	$ 14,969	$ 26,602
Union	$ 73,186	$ 218,766	$ 230,897	$ 261,757	$ 162,328	$ 115,010	$ 204,389
Total	$ 105,000	$ 317,000	$ 344,000	$ 396,000	$ 247,000	$ 175,000	$ 311,000
Total Benefits (Current + Accrued)							
Executive	$ 81,204	$ 96,801	$ 112,840	$ 159,177	$ 165,106	$ 167,065	$ 177,006
Management	$ 593,275	$ 747,421	$ 850,293	$ 906,978	$ 961,428	$ 972,836	$ 1,030,728
Non-Union	$ 229,932	$ 246,260	$ 312,127	$ 323,143	$ 374,552	$ 378,997	$ 401,550
Union	$ 2,080,505	$ 2,428,507	$ 2,603,416	$ 2,708,944	$ 2,877,795	$ 2,911,941	$ 3,085,227
Total	$ 2,984,916	$ 3,518,989	$ 3,878,676	$ 4,098,241	$ 4,378,881	$ 4,430,837	$ 4,694,513
Total Compensation (Salary, Wages, & Benefits)							
Executive	$ 413,579	$ 462,775	$ 527,866	$ 769,186	$ 764,414	$ 778,359	$ 788,301
Management	$ 3,021,598	$ 3,573,192	$ 3,977,675	$ 4,382,773	$ 4,451,264	$ 4,637,163	$ 4,695,056
Non-Union	$ 1,171,065	$ 1,177,295	$ 1,460,133	$ 1,561,516	$ 1,734,120	$ 1,947,394	$ 2,081,976
Union	$ 10,596,189	$ 11,609,953	$ 12,178,791	$ 13,090,374	$ 13,323,748	$ 14,393,375	$ 14,855,503
Total	$ 15,202,431	$ 16,823,215	$ 18,144,465	$ 19,803,848	$ 20,273,546	$ 21,756,291	$ 22,420,836
Compensation - Average Yearly Base Wages							
Executive	$ 134,734	$ 143,250	$ 154,730	$ 150,403	$ 155,244	$ 158,349	$ 158,349
Management	$ 80,383	$ 84,279	$ 85,940	$ 91,234	$ 90,060	$ 91,862	$ 91,862
Non-Union	$ 57,166	$ 56,497	$ 52,549	$ 53,183	$ 51,464	$ 52,493	$ 52,493
Union	$ 58,105	$ 59,486	$ 61,505	$ 62,417	$ 64,565	$ 66,502	$ 66,502
Total	$ 62,147	$ 63,983	$ 65,387	$ 67,305	$ 68,410	$ 69,928	$ 69,718
Compensation - Average Yearly Overtime							
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 4,098	$ 1,986	$ 1,770	$ 2,026	$ 1,643	$ 1,644	$ 1,693
Non-Union	$ 1,224	$ 844	$ 484	$ 487	$ 947	$ 871	$ 837
Union	$ 4,080	$ 4,066	$ 3,766	$ 5,153	$ 5,102	$ 4,925	$ 4,948
Total	$ 5,729	$ 4,989	$ 4,744	$ 7,163	$ 6,613	$ 6,553	$ 6,649
Compensation - Average Yearly Incentive Pay							
Executive	$ 34,000	39,870	53,000	50,267	$ 44,567	$ 41,559	$ 41,559
Management	$ 6,278	7,329	9,175	9,748	$ 10,978	$ 9,944	$ 9,944
Non-Union	$ 2,250	1,338	2,267	1,836	$ 3,100	$ 2,581	$ 2,409
Union	$ 652	-	-	475	$ -	$ -	$ -
Total	$ 9,320	7,296	9,515	3,009	$ 11,689	$ 10,283	$ 9,909
Compensation - Average Yearly Benefits							
Executive	$ 40,602	$ 48,400	$ 56,420	$ 53,059	$ 55,035	$ 55,688	$ 59,002
Management	$ 21,973	$ 24,914	$ 26,572	$ 27,484	$ 28,277	$ 27,795	$ 29,449
Non-Union	$ 14,371	$ 15,391	$ 14,863	$ 14,688	$ 14,982	$ 13,536	$ 13,385
Union	$ 15,076	$ 16,865	$ 17,832	$ 18,181	$ 19,314	$ 18,314	$ 18,928
Total	$ 16,311	$ 18,328	$ 19,297	$ 19,798	$ 20,753	$ 19,693	$ 20,323
Total Compensation	$ 15,202,431	$ 16,823,215	$ 18,144,465	$ 19,803,848	$ 20,273,546	$ 21,756,291	$ 22,420,836
Total Compensation Charged to OM&A	$ 10,544,640	$ 12,160,301	$ 13,595,845	$ 14,958,675	$ 14,467,552	$ 15,543,678	$ 16,013,061
Total Compensation Capitalized	$ 4,657,791	$ 4,662,914	$ 4,548,620	$ 4,845,173	$ 5,805,994	$ 6,212,614	$ 6,407,775

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Ontario Energy Board Interrogatory # 21

Ref: Exhibit 4 / Tab 4 / Schedule 7 / Page 1 – Compensation Cost Reconciliation

Table 1 provided the Total Compensation Reconciliation from 2006 Board Approved to forecast Test Year 2011, please use the same format as Table 1 to provide a yearly reconciliation of the compensation from 2006 actual to 2011.

Response:

This table has been revised:

	2006	2007	2008	2009	2010	2011
	$000	$000	$000	$000	$000	$000
Previous Year Total Compensation	15,519	16,823	18,144	19,804	20,274	21,756
Changes due to:						
- Increased Headcount (Estimated)	296	178	148	207	415	178
- Cumulative Wage Inflation and Progression Adjustments (Estimated)	679	714	979	(162)	958	334
- Pay Equity Adjustments	-	12	-	-	-	-
- Increased Benefit Costs	322	333	168	430	124	128
- Overtime Costs	(35)	(42)	229	(5)	25	26
- Incentive Compensation Costs	41	126	137	1	(39)	-
Current Year Total Compensation	16,823	18,144	19,804	20,274	21,756	22,421

Ontario Energy Board Interrogatory # 22

Ref: Exhibit 4 / Tab 4 / Schedule 8.0 / Page 1 – Hiring Schedule

In the above reference, Hydro One Brampton provided a Hiring schedule for 2010 and 2011. The schedule indicates that 11 out of the total 18 hires would be added as of Q2 of 2010. Please provide an update of the Hiring schedule for 2010 and changes, if any, for 2011.

Response:

POSITION	No. of Hires	Number of Hires by Quarter								Position Rationale
		2010				2011				
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
Accounts Receivable Analyst	1		1							R
Assistant Supervisor – Customer Accounts	1				1					W
Building General Helper	1				1					W
Credit Representative	1					1				W
Customer Accounts Representative	2	1				1				W
Drafting Supervisor	1	1								R
Draftsperson	1		1							R
Engineering Technician	2	1	1							R (1), P (1),
Fleet Mechanic	1				1					S,W
Health, Safety & Environment Coordinator	1					1				S,W
Line Apprentice	3			1	1			1		S
Manager	1						1			W
Conservation & Demand Management (CDM) Representative	1						1			W
Outage Planning Coordinator	1				1					W
Project Engineer	2				1		1			S
(Smart Metering Supervisor)	-1								-1	C
Software Developer	1		1							S,W
TOTAL:	**20**	**3**	**4**	**1**	**6**	**3**	**3**	**1**	**-1**	

Ontario Energy Board Interrogatory # 23

Ref: Exhibit 4 / Tab 5 / Schedule 1.0 / Page 1 – Shared Services / Corporation Cost Allocation

In Table 1, Hydro One Brampton provided the Common Corporate functions and Services. Hydro One Brampton indicates that the costs for Finance for 2010 is $499,000 which represents a 68% increase as compared to 2009 actual ($297,000). Please explain the reason(s) for this increase.

Response:

The increase in Finance charge is primarily due to Controller costs increasing by $135,000 mainly as a result of increased accounting costs, as well as internal audit costs increasing by $64,000 as the percentage of time spent on internal audits for Hydro One Brampton has increased from 1.7% to 3.7%. These increased costs are expected to be on-going.

Ontario Energy Board Interrogatory # 24

Ref: Exhibit 4 / Tab 7 / Schedule 1.0 / Page 2 – Depreciation Review

On page 2, it states: "As part of its transition to IFRS, Hydro One Brampton conducted a review to ensure that the accounting treatment of the Company's property, plant and equipment and intangible assets was in accordance with IAS 16. This review was carried out in consultation with the Company's external IFRS advisors and with Foster Associates Inc." Please provide the results of the review and any report that may have been prepared by Foster Associates Inc.

Response:

The report from Foster Associates Inc. is enclosed **Appendix M.** This depreciation review addresses the componentization of USoA accounts and provides service life estimates to be used in depreciating assets put into service in 2011 and after. The same effective depreciation rates were applied to legacy assets (assets put into service before January 1st 2011). Due to information constraints, these legacy assets will continue to be componentized at a USoA level under IFRS and the Company's IFRS depreciation rates will be applied to these assets at an aggregate level.

Ontario Energy Board Interrogatory # 25

Ref: Exhibit 4 / Tab 7 / Schedule 1.2 – Depreciation Expense Breakdown

In Table 4, Depreciation Expense – 2009, the calculation of the "Total for Depreciation" column is taken into account of 50% of the "Additions" (column d). However, in Table 5 & 6, Depreciation Expense - 2010 & 2011, it appears that the calculation of the "Total for Depreciation column" included 100% of the "Additions" (column d). Please explain this apparent inconsistency.

Response:

Depreciation expense for 2010 and 2011 is based on IFRS where half year depreciation was not applied, whereas depreciation expense for 2009 was based on CGAAP and half year depreciation was applied to additions. Revised tables have now been provided with depreciation expense being calculated under CGAAP and using the half year depreciation on current year additions. See the following table.

Depreciation Expense 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,412,508		1,412,508	349,700	1,587,358	various	4,523
1808	Buildings and Fixtures	29,478,774		29,478,774	435,898	29,696,723	various	591,106
1815	Transformer Station Equipment - Normally Primary above 50 kV	12,011,917		12,011,917	659,356	12,341,595	various	395,503
1820	Distribution Station Equipment - Normally Primary below 50 kV	40,492,279		40,492,279	1,116,600	41,050,579	various	1,355,438
1830	Poles, Towers and Fixtures	61,098,800	4,551,784	56,547,016	6,712,536	59,903,284	25	2,396,131
1835	Overhead Conductors and Devices	19,376,229	373,822	19,002,407	1,790,835	19,897,824	25	795,913
1840	Underground Conduit	17,738,414	774,359	16,964,055	3,098,681	18,513,395	25	740,536
1845	Underground Conductors and Devices	215,034,537	13,404,597	201,629,940	10,178,876	206,719,378	25	8,268,775
1850	Line Transformers	88,592,205	10,901,156	77,691,049	4,376,562	79,879,330	25	3,195,173
1855	Services	23,014,363	1,026,647	21,987,716	661,552	22,318,492	25	892,740
1860	Meters	43,203,730	17,906,989	25,296,741	1,026,750	25,810,116	various	1,720,674
1908	Buildings and Fixtures	310,348	3,131	307,218	-	307,218	25	12,289
1915	Office Furniture and Equipment	1,702,247	1,335,067	367,179	528,000	631,179	10	63,118
1920	Computer Equipment - Hardware	3,199,798	2,291,910	907,888	840,400	1,328,088	5	265,618
1925	Computer Software	-	-	-	-	-	5	-
1930	Transportation Equipment	9,376,602		9,376,602	1,980,000	10,366,602	various	704,519
1935	Stores Equipment	219,670	56,279	163,391	-	163,391	10	16,339
1940	Tools, Shop and Garage Equipment	2,847,869	1,440,330	1,407,539	381,000	1,598,039	10	159,804
1950	Power Operated Equipment	37,250	1,360	35,890	-	35,890	8	4,486
1955	Communication Equipment	605,068	-	605,068	41,600	625,868	10	62,587
1960	Miscellaneous Equipment	140,957	(25)	140,982	-	140,982	10	14,098
1980	System Supervisory Equipment	4,511,464	1,683,246	2,828,218	101,000	2,878,718	15	191,915
1995	Contributions and Grants - Credit	(100,287,257)	(13,448,387)	(86,838,870)	(11,658,493)	(92,668,117)	25	(3,706,725)
2055	Construction Work in Progress--Electric	798,274		798,274	3,216,066	2,406,307	none	-
2040	Electric Plant Held for Future Use	3,369,797		3,369,797	-	3,369,797	none	-
1610	Miscellaneous Intangible Plant - TS CIP	5,118,257		5,118,257	-	5,118,257	none	-
1610	Miscellaneous Intangible Plant - Software CIP	84,843		84,843	-	84,843	none	-
1610	Miscellaneous Intangible Plant - TS in-service	3,045,640		3,045,640	5,268,063	5,679,672	various	204,165
1610	Miscellaneous Intangible Plant - Software in-service	1,940,555		1,940,555	961,600	2,421,355	various	285,563
	TOTAL	496,622,029	42,302,266	454,319,763	32,066,582	470,353,054		18,634,288

Ontario Energy Board Interrogatory # 26

Ref: Exhibit 4 / Tab 8 / Schedule 1.0 / Page 4 – Summary of Income Taxes

In Table 2, Hydro One Brampton provides its summary of income taxes for 2006 Board Approved, 2010 Bridge and 2011 Test. Please expand Table 2 to include the income taxes for the period from 2006 (actual) to 2009 (actual) into Table 2.

Response:

Summary of Income Taxes							
Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Income Taxes	9,083,622	8,772,347	11,831,510	8,447,449	4,974,472	1,894,924	2,520,658
Large Corporation Tax	293,006		-	-	-	-	-
Ontario Capital Tax	864,244	885,666	681,830	713,414	614,388	240,386	-
Total Taxes	**10,240,872**	**9,658,013**	**12,513,340**	**9,160,863**	**5,588,860**	**2,135,310**	**2,520,658**
Note:	**Above per tax returns filed**						
	2007 income tax adjusted for reassessment.						

Ontario Energy Board Interrogatory # 27

Ref: Exhibit 4/ Tab8/ Schedule 3.0 – Property Tax

Exhibit 1 / Tab 2 / Schedule 3.1 – Revenue Requirement Work Form

Please clarify whether the forecasted 2011 property tax amount is included as part of OM&A or Income taxes in the revenue requirement work form.

Response:

A portion of the forecasted 2011 property tax amount is included as part of OM&A in the revenue requirement work form. Property taxes are recorded in overhead accounts, which are then allocated to OM&A and capital as part of building and office allocations.

Ontario Energy Board Interrogatory # 28

Ref: Exhibit 4 / Tab 2 / Schedule 5.1/ Appendix G – Green Energy Plan

a) In its Green Energy Plan, Hydro One Brampton states that the Green Energy Spending for 2010 and 2011 is $1,033,000 and $1,050,000 respectively. Please confirm whether these costs have been included in the revenue requirement.

Response:

Yes

b) If the Green Energy spending is not included in the revenue requirement, please explain how Hydro One Brampton proposes to recover the spending.

Response:

N/A

c) Please provide the latest update of the spending in 2010.

Response:

Spending as of June 30th 2010 for Green Energy is $692k.

d) Please clarify whether there are costs related to Expansion and Renewable Enabling Improvement that Hydro One Brampton has included in the Green Energy Plan. If so, please provide amounts for these two types of costs.

Response:

Yes, we have budgeted for Expansion and Enabling Improvements as follows:

	2010	**2011**
Expansions	$0	$200k
Enabling Improvements	$300k	$100k

Ontario Energy Board Interrogatory # 29

Ref: Exhibit 4 / Tab 2 / Schedule 5.1/ Appendix G / Page 3;

Report of the Board: Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09, issued June 10, 2010 [EB-2009-0349];

Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence, issued March 25, 2010 [EB-2009-0397]

With respect to the filed GEA Plan:

a) Is the plan filed a "Basic" or "Detailed" GEA Plan, within the definition of the *Filing Requirements*?

Response:

The GEA Plan filed is a "Basic" Plan.

The Letter of Comment (see OEB-Q29-D) received back from the OPA concurs that it is a "Basic" Plan.

b) Has Hydro One Brampton consulted with its host distributor and upstream transmitter when preparing its GEA plan?

Response:

Yes we consulted with Hydro One Networks Inc.

c) Has Hydro One Brampton participated in planning meetings with the

OPA?

Response:

Yes.

The following applies to parts (d) and (e) of this question. The *Filing Requirements* state that, "Distributors should submit no less than 30 days in advance of the date the distributor needs to receive the OPA letter for inclusion in the cost of service application." Further, at page 7 of the *Filing Requirements*, the Board indicates for GEA plans, that, "the OPA comment letter must be filed with the GEA plan, and any response to the letter from the distributor must be included in the application or reflected in the GEA plan as filed."

d) It is a requirement that the OPA letter be filed with the Board.

I. When did Hydro One Brampton file its Plan with the OPA?

II. Please file the letter of comment from the OPA, or

III. If Hydro One Brampton cannot provide the letter of comment,

indicate reasons given and when Hydro One Brampton expects to receive the letter of comment.

Response:

1. June 29, 2010
2. See **Appendix N**
3. Not Applicable

e) Hydro One Brampton indicates at page 3 of Appendix G that the plan is in alignment with Hydro One Brampton's corporate strategy. Please provide details as to which area of Hydro One

Brampton's corporate strategy applies in this fashion.

Response:

The Green Energy Plan will align with the following HOBNI Corporate Strategies:

- Achieve Environmental Excellence – Accommodating and connecting FIT and MicroFIT applications as per OPA requirements.
- Continuous Innovation – Developing and implementing Smart Grid technology while leveraging Smart Meter technology.

Ontario Energy Board Interrogatory # 30

Ref: Exhibit 4 / Tab 2 / Schedule 5.1/ Appendix G / Page 8 and 12– Green Energy Plan - Distributor's current and future system capacity

a) Has Hydro One Brampton provided a list of all feeders that are directly connected to a transformer station that is directly connected to a transmission system or a host distributor system?

Response:

No.

b) Please provide a list of all feeders for which the OPA has received one or more applications from renewable generators under the FIT program.

Response:

25M1	Yarrow	27.6	kV
25M3	Yarrow	27.6	kV
25M4	Yarrow	27.6	kV
25M10	Yarrow	27.6	kV
25M11	Yarrow	27.6	kV
42M10	Pleasant	27.6	kV
42M13	Pleasant	27.6	kV
42M14	Pleasant	27.6	kV
42M24	Pleasant	44	kV
42M44	Pleasant	27.6	kV
74M2	Bramalea	27.6	kV
74M4	Bramalea	27.6	kV
74M6	Bramalea	27.6	kV
74M10	Bramalea	27.6	kV
74M27	Bramalea	44	kV
74M28	Bramalea	44	kV
74M43	Bramalea	44	kV
74M44	Bramalea	44	kV
74M47	Bramalea	44	kV
74M48	Bramalea	44	kV
136M41	Goreway	27.6	kV
136M43	Goreway	27.6	kV
136M44	Goreway	27.6	kV
136M45	Goreway	27.6	kV
136M46	Goreway	27.6	kV
136M47	Goreway	27.6	kV
136M49	Goreway	27.6	kV
136M50	Goreway	27.6	kV
136M51	Goreway	27.6	kV
136M52	Goreway	27.6	kV

c) At page 12 of Appendix G, Hydro One Brampton indicates that, "connection requests that

are in excess of available system capacity will be assessed with respect to whether they can be enabled with economic additions to wires facilities." Does Hydro One Brampton consider the figure at page 8 of Appendix G of 719.5MW as the available system capacity, or does Hydro One Brampton use a lower figure to account for feeders that will not be able to accept connections? Has this adjustment already been made?

Response:

719.5 MW is the available system capacity. The adjustment has already been made.

d) At page 10 of Appendix G, for the 12 new feeders proposed as part of the plan, does Hydro One Brampton have any indication of the number of applications and total kW installed capacity of application with the OPA that are associated with these proposed feeder lines?

Response:

The new feeders are required to support planned growth. Currently there are no renewable generation applications that would be associated with the 12 new proposed feeders.

Ontario Energy Board Interrogatory # 31

Ref: Exhibit 4 / Tab 2/ Schedule 5.1/ Appendix G/ Page 11 – Green Energy Expenditures under GEA Plan – List of FIT Applications

Hydro One Brampton provided a map of FIT applications at Page 11 of its GEA

Plan, and Hydro One Brampton notes in evidence that October 21, 2009 is the date associated with cost-responsibility rules as set out in the DSC and thus under the provincial recovery mechanism as set out in section 79.1 of the *OEB Act*.

a) Were all FIT and micro-FIT project applications filed on or after the October 21, 2009 date? If not, please indicate which projects were filed prior to October 21, 2009, and under what scheme (e.g. RESOP)

Response:

Yes, all FIT and micro-FIT applications were filed on or after October 21, 2009

b) Please provide a table, and provide the following information in column form for each FIT project as noted in the figure at the bottom of page 11 of Appendix G (Hydro One Brampton's GEA plan):

I. Final approval from OPA? (Y/N) II. Nameplate capacity of project

III. Available capacity? (Y/N)

IV. Feeder connection (e.g. M22, etc.), MW, and voltage level V. Expected completion or in-service date

Response:

HOB FIT Que #	Kw Capacity	Address	FIT Contract Reference	Available Capacity	HOB Feeder Nbr	HOB Feeder Voltage	Expected In-Service Date
	500	8905 Goreway Dr	FIT-FGLZ4HP	Yes	136M50	27.6kv	Jan-11
	500	26 Kenview Blvd	FIT-F3S568V	Yes	136M52	27.6kv	Jan-11
	500	420 Deerhurst Dr	FIT-FTK14W0	Yes	136M50	27.6kv	Jan-11
	250	76 Wentworth Crt	FIT-FQ5BEWJ	Yes	136M50	27.6kv	Jan-11
HOB-1000	75	223 Wikinson Rd	FIT-F313PDM	Yes	74M6	27.6kv	Nov-10
	200	630 Peter Robertson Blvd	FIT-FFURNWW	Yes	136M44	27.6kv	Jan-11
	200	3918-3998 Cottrelle Blvd	FIT-FWZF6YN	Yes	136M52	27.6kv	Jan-11
	150	365 Deerhurst Dr	FIT-F343L3N	Yes	136M50	27.6kv	Jan-11
	100	95 Deerhurst Dr		Yes	136M50	27.6kv	Jan-11
	100	19 Armthorpe Rd	FIT-FPHECOL	Yes	136M50	27.6kv	Jan-11
	150	15-17 Armthorpe Rd	FIT-FNPFZAQ	Yes	136M50	27.6kv	Jan-11
	100	8800 The Gore Rd	FIT-F5H4X2L	Yes	136M52	27.6kv	Jan-11
	50	73 Ward Rd	FIT-FGPNLC7	Yes	136M46	27.6kv	Jan-11
	50	77 Ward Rd	FIT-F4KJXBM	Yes	136M46	27.6kv	Jan-11
	50	41 Delta Park		Yes	136M51	27.6kv	Jan-11
	500	11 Kenview Blvd		Yes	74M2	27.6kv	Jan-11
	250	25 Precidio Crt		Yes	136M43	27.6kv	Jan-11
	250	2250 Steeles Ave E		Yes	74M27	27.6kv	Jan-11
	500	9105 Airport Rd	FIT-FRDNVNT	Yes	136M51	27.6kv	Jan-11
	450	60 Great Lakes Blvd	FIT-FCB3AAL	Yes	42M13	27.6kv	Jan-11
	450	49 First Gulf Blvd	FIT-FDQ72BG	Yes	25M3	27.6kv	Jan-11
	375	85 Steeles Ave W	FIT-F6MR9CA	Yes	25M11	27.6kv	Jan-11
	20.5	175 Sandalwood Pky W		Yes	42M14	27.6kv	Jan-11
	100	1 Presidents Circle	FIT-F5CXUCE	Yes	25M10	27.6kv	Jan-11
	77	2250 Bovaird Dr E		Yes	136M44	27.6kv	Jan-11
	150	11 Automatic Dr	FIT-F6E29MG	Yes	136M43	27.6kv	Jan-11
	500	78 Walker	FIT-FWT82F1	Yes	74M27	44kv	Jan-11
	450	1600 Clarke Blvd	FIT-FJZ6QY3	Yes	74M43	44kv	Jan-11
	450	29 Melanie Dr		Yes	74M10	27.6kv	Jan-11
	500	165 Summerlea Rd	FIT-FMV2QH7	Yes	136M46	27.6kv	Jan-11
	500	1325 Clarke Blvd	FIT-FP41KVU	Yes	136M46	27.6kv	Jan-11
	150	1327 Clarke Blvd	FIT-FP49043	Yes	74M43	44kv	Jan-11
	50	128 Hedgedale Rd	FIT-F6X38ML	Yes	74M6	27.6kv	Jan-11
	300	170 Steelwell Ave	FIT-FDLJTV1	Yes	74M6	27.6kv	Jan-11
	200	365 - 2 Deerhurst		Yes	136M50	27.6kv	Jan-11
	450	5 Resolution		Yes	25M3	27.6kv	Jan-11
	250	20 Resolution		Yes	25M1	27.6kv	Jan-11
	500	30 Resolution		Yes	25M1	27.6kv	Jan-11
	450	317 Rutherford Rd	FIT-F4D9MC8	Yes	25M1	27.6kv	Jan-11

Ontario Energy Board Interrogatory # 32

Ref: Exhibit 4 / Tab 2/ Schedule 5.1/ Appendix G/ Page 3,15,18,22;

***Filing Requirements*: *Distribution System Plans – Filing under Deemed Conditions of Licence*, issued March 25, 2010 [EB-2009-0397]**

Green Energy Expenditures under GEA Plan – Smart Grid

The *Filing Requirements* state that, "At the present time, smart grid development activities and expenditures should be limited to smart grid demonstration projects, smart grid studies or planning exercises and smart grid education and training… …the Board does not expect distributors to be engaging in the research and development activities related to smart grid development at this time."

a) Hydro One Brampton indicates at page 15 of 24 of its plan that,

"Investments in [the generation connections] area allow HOBNI to undertake further research and development to understand and address the complexities associated with generation connections and the development of new standards for generation connections". Please explain why these amounts should not be characterized as research and development, and thus excluded from costs recoverable through Hydro One Brampton's GEA plan.

Response:

These amounts are associated with the development of new metering standards for the generation connections, the selection and implementation of monitoring equipment for the generation connections (250 kW and greater), the preparation of forms and documents for generation connections and the setup up and training costs associated with the modeling of the generators using a power systems program.

b) Similar to the above, at page 18 of 24 of its GEA Plan, please explain for

"research and pilot projects" why research to "test and prove new and emerging technologies" should be allowed for recovery in the context of the *Filing Requirements*.

Response:

As per the Board's interpretation of O. Reg. 330/09:

"Eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, are not limited to only the initial capital investment costs but also includes the up-front OM&A costs necessary for the purpose of "enabling the connection of a qualifying generation facility".

The Smart Grid projects that HOBNI will research and develop will not only benefit Load customers but will also be developed to accommodate the connection of qualifying renewable generation customers. HOBNI feels that the costs associated with this research qualifies as an "eligible investment" as outlined in the Board's interpretation above.

c) At page 22 of Hydro One Brampton's GEA Plan, a Smart Grid budget is presented with one line item. Please provide a breakdown of what comprises the $733,000 in 2010, and amounts in subsequent years in the table. Please do not classify items as "other" unless they amount to less than $50,000 for a particular budgeted item.

Response:

Please see the table below.

Smart Grid	2010	2011	2012	2013	2014	2015

44kV SCADA	$523k	$300k	$306k	$312k	$318k	$325k
27.6 kV SCADA	$190k	$100k	$102k	$104k	$106k	$108k
Trip Saver	$20k	-	-	-	-	-
Smart Meter / Smart Grid Integration	$0	$350k	$357k	$364k	$371k	$379k
Totals	**$733k**	**$750k**	**$765k**	**$780k**	**$796k**	**$812k**

1

Ontario Energy Board Interrogatory # 33

Ref: Exhibit 4 / Tab 2/ Schedule 5.1/ Appendix G/ Page 4,7;

***Filing Requirements*: Distribution System Plans – Filing under Deemed Conditions of *Licence*, issued March 25, 2010 [EB-2009-0397];**

Ontario Energy Board -- *Distribution System Code* – Appendix F: *Process and Technical Requirements for Connecting Embedded Generation Facilities*

Green Energy Expenditures under GEA Plan Feeder limitations and system capacity and expansion estimates

a) At page 4 of the GEA Plan, please provide further explanation as to why Bramalea TS, and its "EZ bus" are unable to accommodate any renewable facilities connections. Please include details regarding current short circuit fault level at Bramalea TS on feeders M43, M44, M47, and M48.

Response:

The Maximum 3-Phase Symmetrical short circuit rating that customer equipment has to be designed to withstand at 44 kV is 1500 MVA. Any additional renewable generation will cause the existing fault level on the Bramalea 44 kV "EZ bus" to exceed the 1500 MVA limit placing existing customers at risk.

b) At page 7 of the GEA Plan Hydro One Brampton has provided an explanation of each planning criteria and why these must be observed (e.g. p.u. bus voltages, bus voltage swing, line loading as % of thermal rating and rated kVA. Please confirm that Hydro One Brampton is meeting the requirements as set out in the Distribution System Code with respect to the criteria applied.

Response:

Hydro One Brampton is meeting the requirements as set out in the Distribution System Code for "Voltage Variation Limits".

Line Loading and Reverse Power Flow percentages were set by Hydro One Brampton for control of reverse power flow during light load conditions.

c) What limits renewable connections from connecting to the existing 8.32 kV and 4.36 kV systems other than that these systems will become obsolete?

Response:

The only other limits preventing renewable generation connections on the 8.32 kV and 4.16 kV systems are as follows:

The thermal rating of the existing

The 4.16 kV bus fault level ratings. (8.32 kV systems have no stations)

d) Regarding the last 4 bullets on page 7 indicating short circuit (SC) limitations Please confirm that the following items are the available SC capacities and are strictly limited by the applicable bus on Hydro One Brampton's system:

I. SC not to exceed 20kA at the HONI 44/27.6 kV bus

Response:

The available Short Circuit capacity on Hydro One Brampton's 44 kV bus systems, connected to the HONI 44 kV bus, is strictly limited to a maximum value of 19,683 Amps.

The available Short Circuit capacity on Hydro One Brampton's 27.6 kV bus systems, connected to the HONI 27.6 kV bus is strictly limited to a maximum value of 16,735 Amps.

II. SC not to exceed 20kA for the 27.6kV bus at Jim Yarrow TS

Response:

The available Short Circuit capacity on Hydro One Brampton's 27.6 kV bus systems connected to the 27.6 kV bus at Jim Yarrow TS is strictly limited to a maximum value of 16,735 Amps

III. SC not to exceed 20kA for the HOBNI MS

Response:

The available Short Circuit capacity on Hydro One Brampton's 13.8 kV Municipal Stations bus systems is strictly limited to a maximum bus value of 20,000 Amps.

The available Short Circuit capacity on Hydro One Brampton's 4.16 kV Municipal Stations bus systems is strictly limited to a maximum bus value of 25000 Amps.

IV. SC not to exceed 16kA for load modules and customer breakers

Response:

The available Short Circuit capacity on Hydro One Brampton's load modules and customer breakers is strictly limited to a maximum Hydro One Brampton feeder value of 16,735 Amps at 27.6 kV.

The available Short Circuit capacity on Hydro One Brampton's load modules and customer breakers is strictly limited to a maximum Hydro One Brampton feeder value of 20,000 Amps at 13.8 kV.

The available Short Circuit capacity on Hydro One Brampton's load modules and customer breakers is strictly limited to a maximum Hydro One Brampton feeder value of 25000 Amps at 4.16 kV.

e) Please explain why M21 is not suitable for connection of renewable facilities.

Response:

The Pleasant 42M21 feeder was removed from the HOBNI system 10 years ago. Back in 2006 Hydro One showed interest for the unused breaker position and HOBNI agreed to surrender the 42M21 breaker position to HONI. The Transmission Connecting Agreement between HONI and HOBNI is currently in the process of being modified to reflect the removal of the 42M21 breaker position.

Ontario Energy Board Interrogatory # 34

Ref: Exhibit 4 / Tab 2/ Schedule 5.1/ Appendix G/ Page 3;

***Report of the Board*: *Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09*, issued June 10, 2010 [EB-2009-0349], Executive Summary and Page 15, footnote 9.**

Green Energy Expenditures under GEA Plan – Relief Sought and Contribution Factors

In the *Report of the Board* under the Executive Summary section, the Board states that, "Distributors that file a Basic GEA Plan will be permitted to undertake a basic (i.e., standardized) direct benefit assessment, while essentially all distributors required to file a Detailed GEA Plan will be required to undertake a detailed direct benefit assessment based on the principles and criteria set out in this Report. Further at page 15, footnote 9 of the *Report of the Board* the Board provided an example, that, "For example, based on the provisionally approved methodology and allocation (i.e., dollar amounts) proposed by Hydro One as part of its 2010 and 2011 distribution rates application, those dollar amounts represent 6% for REI [Renewable Enabling Improvement] investments and 17% for Expansion investments."

a) What specific relief, if any, is Hydro One Brampton seeking with respect to its Green Energy plan in 2011? Please include a direct benefit assessment calculation.

Response:

Hydro One Brampton will seek approval to include these Green Energy costs as part of the revenue requirement to be funded as described below:

OM&A costs included in the Green Energy Plan covers administrative and technical assessment work related to generation connections. Investments in this area will also address the increasing needs to interface with generator connection proponents as a result of the forecasted increases in connection volumes. These costs will be recoverable fully from the Generator.

Expansion costs included in the Green Energy Plan covers capital investments to modify/upgrade the distribution system to allow the connection of one or more renewable generation facilities to Hydro One Brampton's distribution system while preserving reliability and power quality. Hydro One Brampton will contribute up to the maximum expansion cost cap of $90,000 per MW of connecting generator capacity established under the DSC. Any incremental Expansion costs beyond the proposed cap are to be borne by the Generator(s). The renewable generation that is anticipated to connect to Hydro One Brampton's distribution system is expected to provide benefits to all electricity consumers in the Province. There are circumstances where Expansion investments are also expected to provide a benefit to Hydro One Brampton's load customers. Consistent with the requirements of Regulation 330/09 a portion of this investment cost has been identified for recovery through the distribution rates, with the balance to be recovered from all electricity consumers in the Province. Currently, Hydro One Brampton only anticipates needing to upgrade and replace padmounted distribution transformers to accommodate the connection of renewable generation. These investments would be subject to a financial evaluation to determine the benefit to Hydro One Brampton load customers based on the Net Present Value ("NPV") of the "consumed portion" of the asset replaced on a "like-for-like" basis. The sample of transformers to be replaced in the Green Energy Plan has an average in-service life of 15 years (Padmount Transformer Life Span is typically 40 years). HOBNI proposes that this investment be shared equally with load customers and provincial rate payers, resulting in an estimated benefit to HOBNI customers of 18.75% and will be recovered through HOBNI distribution rates, with the balance of the investment being allocated to Provincial ratepayers.

Renewable Enabling Improvement (REI) costs included in the Green Energy Plan will ensure proper protection, automation and control measures are in place to facilitate the connection and operation of renewable generation. The majority of these investments will provide benefits to the Province as a whole, while a relatively small portion of these investments are also expected to provide some benefits to Hydro One Brampton's load customers. Consistent with the requirements of Regulation 330/09 a portion of the REI investment cost has been identified for recovery through the distribution rates, with the balance to be recovered from all provincial ratepayers. Currently the projects identified in the REI section of the Green Energy Plan are for the installation of monitoring equipment as required by the transmitter. These projects are seen to have zero (0) benefit to HOBNI load customers, and as such 100% of the investment should be allocated to the Provincial ratepayers.

Smart Grid costs included in the Green Energy Plan that will help enable the connection of renewable generation are identified as SCADA type projects. These projects will ensure proper protection, automation and control measures are in place to facilitate the connection and operation of renewable generation. These projects will be chosen based on the most heavily loaded feeders and the area with great potential for generation connection. These investments will provide benefits to both the Province and HOBNI load customers. Consistent with the requirements of Regulation 330/09 a portion of the REI investment cost has been identified for recovery through the distribution rates, with the balance to be recovered from all provincial ratepayers. The projects identified in the Smart Grid (SCADA) section of the HOBNI Green Energy Plan are seen to have 50% benefit to HOBNI load customers, with the remaining 50% of the investment allocated to the Provincial ratepayers

b) Please identify the components and proportions of the plan that Hydro One Brampton is expecting to be borne by their own ratepayers, the provincial ratepayers, and the shareholder(s). Please specifically indicate the approximate percentages that Hydro One Brampton intends to recover at this time with respect to REI investments and expansion investments from provincial ratepayers.

Response:

HOBNI Green Energy Investment	Allocation of Cost Responsibility		
	Generator	Provincial Ratepayers	HOBNI Customers
OM&A	100%	-	-
Expansions (up to threshold)	-	81.25%	18.75%
Renewable Enabling Improvements	-	100%	0%
Smart Grid (SCADA Only)	-	50%	50%

Ontario Energy Board Interrogatory # 35

Ref: Exhibit 4 / Tab 2/ Schedule 5.1/ Appendix G/ Page 15 – Generator Connection Capital Spending

A table of generator Connection Spending has been provided for the years 2010-2015 at Page 15 of Hydro One Brampton's GEA Plan, which is a composite of tables for generator Connections and Smart Grid and OM&A, provided later in the report.

a) Is the basis for the forecast estimate of capital for Generator Connections the 25 MicroFIT and 75 FIT project application received for the period Nov 29, 2009 to present date, as mentioned on page 11?

Response:

Yes.

b) Should it be understood that the 28 FIT and 70 microFIT projects listed in evidence involves spending applied in 2010? Or are these actual applications applicable to the 2011 year?

Response:

Ten (10) microFIT projects have been connected in 2010, and we expect to connect less than three FIT projects in 2010. Twenty three (23) of the twenty eight (28) FIT projects will be connected in 2011. HOBNI expects to connect at least 60 microFIT projects in 2011. Costs for these projects will occur in 2011.

c) Is it assumed that the same number of applications (as in part "a" of this question i.e. 25 and 75 respectively) is received each year? What is the basis of the expenditure in each year?

Response:

The number of FIT and micro-FIT forecasted in the Green Energy Plan is based on trending from October 21, 2009 to May 2010. HOBNI expects these numbers to continue for the next 5 to 7 years as long as OPA incentive program exists.

d) Please indicate the number of Generator Connections that Hydro One BramptonI is aware of actually being required on the basis of FIT or MicroFit applications, or by whatever indications there are, for each year.

Response:

We have a total of 112 FIT prefit applications. 111 are allocation exempt.

We have a total of 71 MicroFit applications listed through the OPA's portal. 10 have been connected in 2010.

e) Please provide voltage, MW, type and connection point of the known FIT or MicroFit projects in the Hydro One Brampton service area.

Response:

Proposed FIT Projects

HOB	Gen -	Type	Transformer Details

#	kW Capacity		Ownership	Connection Point Tx #	Primary Voltage	Tx Size (kVA)	Tx type
1	500	Solar	HOB	T16129	27.6kv	1000	pad
2	500	Solar	C.O.	T80099	27.6kv	5000	c/o
3	500	Solar	HOB	T11894	27.6kv	1500	vault
4	250	Solar	HOB	T5813	27.6kv	500	vault
5	75	Solar	C.O.	T10287	27.6kv	300	pole
6	200	Solar	HOB	T5456	27.6kv	1500	vault
7	200	Solar	HOB	T16481	27.6kv	1500	pad
8	150	Solar	HOB	T10289	27.6kv	500	pad
9	100	Solar	HOB	T11387	27.6kv	500	pad
10	100	Solar	HOB	T10992	27.6kv	1000	vault
11	150	Solar	HOB	T10992	27.6kv	1000	vault
12	100	Solar	HOB	T17280	27.6kv	1500	pad
13	50	Solar	HOB	T460	27.6kv	300	pole
14	50	Solar	HOB	T460	27.6kv	300	pole
15	50	Solar	HOB	T3199	27.6kv	300	pole
16	500	Solar	HOB	T3169	27.6kv	1500	vault
17	250	Solar	C.O.	T80155	27.6kv	2000	c/o
18	250	Solar	C.O.	T80146	27.6kv	4000	c/o
19	500	Solar	HOB	T16610	27.6kv	750	pad
20	450	Solar	HOB	T11817	27.6kv	750	pad
21	450	Solar	HOB	T6551	27.6kv	750	vault
22	375	Solar	HOB	T16310	27.6kv	1500	pad
23	20.5	Solar	HOB	T2432	27.6kv	1500	vault
24	100	Solar	C.O.	T80246	27.6kv	5000	c/o
25	77	Solar	HOB	T17418	27.6kv	1000	pad
26	150	Solar	HOB	T819	27.6kv	300	pole
27	500	Solar	C.O.	T80189	44kv	3000	c/o
28	450	Solar	C.O.	T80015	44kv	3000	c/o
29	450	Solar	HOB	T1754	27.6kv	750	vault
30	500	Solar	HOB	T11700	27.6kv	750	pad
31	500	Solar	HOB	T11544	27.6kv	750	pad
32	150	Solar	C.O.	T80161	44kv	5000	c/o
33	50	Solar	HOB	T3910	27.6kv	300	pad
34	300	Solar	HOB	T12967	27.6kv	500	pad
35	200	Solar	HOB	T10289	27.6kv	500	pad
36	450	Solar	HOB	T17463	27.6kv	1000	pad
37	250	Solar	HOB	T16026	27.6kv	750	pad
38	500	Solar	HOB	T17462	27.6kv	1500	pad
39	450	Solar	HOB	T16382	27.6kv	1000	pad

40	500	Solar	HOB	T1661	27.6kv	1000	vault
41	200	Solar	HOB	T9542	13.8kv	225	pole
42	50	Solar	HOB	T8553	13.8kv	500	pad
43	50	Solar	HOB	T7511	27.6kv	150	pole
44	500	Solar	HOB	T11479	27.6kv	750	pad
45	250	Solar	HOB	T11342	27.6kv	1500	vault
46	500	Solar	HOB	T10051	27.6kv	300	pole
47	300	Solar	HOB	T80082	44kv	1000	c/o
48	200	Solar	HOB	T13010	27.6kv	750	pad
49	450	Solar	HOB	T1754	27.6kv	750	vault
50	250	Solar	HOB	T2740	27.6kv	500	pad
51	450	Solar	HOB	T2646	27.6kv	1500	pad
52	500	Solar	C.O.	T80188	44kv	4000	c/o
53	500	Solar	C.O.	T90053	44kv	2000	c/o
54	500	Solar	HOB	T17104	27.6kv	1000	pad
55	500	Solar	HOB	T11703	27.6kv	750	pad
56	3200	Solar	C.O.	new	27.6kv	4000	c/o
57	500	Solar	HOB	T10391	27.6kv	1000	pad
58	77	Solar	HOB	T3050	27.6kv	1500	vault
59	200	Solar	HOB	T3170	27.6kv	750	vault
60	500	Solar	co	T80025	44kv	16000	c/o
61	250	Solar	HOB	T15263	27.6kv	750	pad
62	13.5	Solar	HOB	T16149	27.6kv	300	pad
63	250	Solar	HOB	T14696	27.6kv	1500	pad
64	150	Solar	HOB	T6536	27.6kv	500	vault
65	500	Solar	HOB	T12032	27.6kv	500	pad
66	250	Solar	HOB	T11360	27.6kv	300	pad
67	250	Solar	HOB	T10059	27.6kv	300	pole mount
68	250	Solar	HOB	T16238	27.6kv	1000	pad
69	250	Solar	HOB	T13329	27.6kv	500	pad
70	250	Solar	C.O.	T80020	44kv	2500	c/o
71	200	Solar	HOB	T10505	27.6kv	300	vault
72	250	Solar	C.O.	T80180	27.6kv	2500	c/o
73	250	Solar	C.O.	T80173	44kv	2500	c/o
74	120	Solar	HOB	T10486	27.6kv	300	pole
75	500	Solar	HOB	T12223	27.6kv	500	pad
76	500	Solar	HOB	T11892	27.6kv	1000	pad
77	250	Solar	HOB	T12687	27.6kv	750	pad
78	250	Solar	HOB	T11549	27.6kv	750	pad
79	250	Solar	HOB	T5201	27.6kv	750	vault
80	250	Solar	HOB	T5157	27.6kv	750	vault
81	250	Solar	HOB	T5397	27.6kv	1000	vault

82	500	Solar	C.O.	T80138	27.6kv	2500	station
83	250	Solar	HOB	T12936	27.6kv	750	pad
84	500	Solar	C.O.	T80066	44kv	3000	station
85	89	Solar	HOB	T900	27.6kv	750	vault
86	109	Solar	HOB	T1699	27.6kv	500	vault
87	66	Solar	HOB	T3795	27.6kv	300	pole
88	256	Solar	HOB	T1726	27.6kv	500	vault
89	153	Solar	HOB	T900	27.6kv	750	vault
90	150	Solar	HOB	T473	27.6kv	225	vault
91	22	Solar	HOB	T16487	27.6kv	300	pad
92	75	Solar	HOB	T1215	27.6kv	300	vault
93	250	Solar	HOB	T13318	27.6kv	500	pad
94	250	Solar	HOB	T2928	27.6kv	300	vault
95	250	Solar	HOB	T5016	27.6kv	1500	vault
96	250	Solar	HOB	T5016	27.6kv		
97	250	Solar	HOB	T2743	27.6kv	750	vault
98	250	Solar	HOB	T2743	27.6kv		
99	250	Solar	HOB	T2743	27.6kv		
100	250	Solar	HOB	T2743	27.6kv		
101	155	Solar	HOB	T11360	27.6kv	300	pad
102	500	Solar	HOB	T16027	27.6kv	750	pad
103	100	Solar	HOB	T2937	27.6kv	300	vault
104	250	Solar	HOB	T3081	27.6kv	225	pole
105	100	Solar	HOB	T8660	27.6kv	500	pole
106	230	Solar	HOB	T5101	27.6kv	300	vault
107	80	Solar	HOB	T11801	27.6kv	500	pad
108	63	Solar	HOB	T2577	27.6kv	300	pole
109	40	Solar	HOB	T2577	27.6kv	300	pole
110	10	Solar	HOB	T2744	27.6kv	150	pad
111	150	Solar	HOB	T851	27.6kv	150	pole
112	220	Solar	HOB	T12353	27.6kv	500	pad

Proposed micro-FIT Projects

kW	Type	Connection Point @ Customer Service
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
2.8	Solar	Parallel

10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
4.2	Solar	Parallel
7	Solar	Parallel
10	Solar	Parallel
9	Solar	Parallel
4.5	Solar	Parallel
7	Solar	Parallel
10	Solar	Parallel
5	Solar	Parallel
2	Solar	Parallel
3	Solar	Parallel
2	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
6	Solar	Parallel
2.8	Solar	Parallel
10	Solar	Parallel
2.8	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
6	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
5	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
10	Solar	Parallel
5	Solar	Parallel
10	Solar	Parallel

f) What is the typical lead time, MW/kW size, and time to complete the average project? What is the range of expected lead times to complete these projects?

Response:

For an average 250 to 500 kW project, typical lead time to complete the Customer Impact Assessment (CIA) is 60 days. The time to complete connection is dependent on the customer and also if transformation upgrades are required; but typically 14 -16 weeks.

g) "Expansion (capital)" spending is shown in the table on page 15 and is described as being based on various criteria shown on Page 16. Please indicate what are the specific projects and assumptions that have been made in deriving row "Expansions (Capital)" in the table in each year.

Response:

HOBNI are planning to upgrade the transformation (i.e.: vault, pad-mount, pole mount or station type) at customer facilities when the generation output exceeds existing transformation capability. In 2011 HOBNI will upgrade transformation at the following locations:

Solar kW	Address	Customer	Tx #	Primary Voltage	Existing tx Size (kVA)	Type	Proposed New Tx Size (kVA)
500	109 Summerlea Rd	Metrus - Ozz	T10051	27.6kV	300	pole mount	1000kVA pad
450	27 Melanie Dr	Metrus - Ozz	T1754	27.6kV	750	vault	1000kVA vault
500	2 Edvac Dr	Jobal	T12032	27.6kV	500	pad	1000kVA pad
500	2250 North Park Dr	Waterview Ontario	T12223	27.6kV	500	pad	1000kVA vault
250	8500C Torbram Rd	Solar Stream	T2743	27.6kV	750	vault	1500kVA
155	6 Tracey Blvd	Fit Solar systems	T11360	27.6kV	300	pad	500kVA

Ontario Energy Board Interrogatory # 36

Ref: Exhibit 5 / Tab 1/ Schedule 2.0 Long-term Debt

On page 2, it states: "At the end of 2009 HOBNI had $143 million of long-term debt with Hydro One Inc. at an annual interest rate of 6.95%. HOBNI proposes to add $10 million of new long-term debt with Hydro One Inc. in 2010, and another $47 million in 2011. This new debt has an assumed 30 year term at an annual interest rate of 5.71% and 6.41% respectively."

a) Please advise whether the 2010 new debt has been executed. If so, what is the actual debt rate? Please provide the terms of the agreement.

Response:

No new debt has been issued by the parent for 2010.

b) When is the new debt for 2011 expected to be issued?

Response:

Hydro One Brampton's debt financing strategy takes into consideration the objectives of cost effectiveness, distributing debt maturities evenly over time, and ensuring the term of the debt portfolio is compatible with the long life of the Company's assets. As such, for planning purposes, debt is forecast to be issued mid-year.

c) Please provide the updated interest rate assumption for the new 2011 debt instrument and explain how the rate was determined

Response:

Hydro One Brampton does not plan to update the forecast 2011 debt costs.

Ontario Energy Board Interrogatory # 37

Ref: Exhibit 5 / Tab 2/ Schedule 1.0 – Capital Structure

a) Please confirm whether the transition of the capital structure started in 2008.

Response:

HOBNI confirms that the transition of its capital structure started in 2008.

b) If the answer to (a) is affirmative, please update the capital structure for 2007 and 2008 in Table 3 and 4.

Response:

Table 3: Deemed Capital Structure for 2007

Deemed Capital Structure for 2007				
Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	149,163,737	55.00%	6.95%	10,366,880
Unfunded Short Term Debt				
Total Debt	149,163,737	55.00%		10,366,880
Common Share Equity	122,043,057	45.00%	9.00%	10,983,875
Total equity	122,043,057	45.00%		10,983,875
Total Rate Base	271,206,794	100.00%	7.87%	21,350,755

Table 4: Deemed Capital Structure for 2008

Deemed Capital Structure for 2008				
Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	163,658,661	57.50%	6.95%	11,374,277
Unfunded Short Term Debt				
Total Debt	163,658,661	57.50%		11,374,277
Common Share Equity	120,965,097	42.50%	9.00%	10,886,859
Total equity	120,965,097	42.50%		10,886,859
Total Rate Base	284,623,759	100.00%	7.82%	22,261,136

Ontario Energy Board Interrogatory # 38

Ref: Exhibit 11 / Tab 1/ Schedule 2.0 – 2011 Cost Allocation Model

a) In Sheet I6, under the row of 'Number of Bills', indicates that the number of bills for the Street Light class is 505,899. Please confirm whether Hydro One Brampton is issuing bills to the Street Light class by connections or customers.

Response:

Hydro One Brampton is issuing bills to the Street Light class by customers. The 505,899 number of bills data used in the Cost Allocation Model for the Street Light Class is incorrect. There are two customers in this class and 24 bills in a year for this customer class. Hydro One Brampton has updated its Cost Allocation Model to correct for this data issue. In addition, Hydro One Brampton has identified a data issue for the Street Light Class on row 38 of Sheet I6 pertaining to the "Total Number of Customer Excluding Connections", the incorrect value 42,158 has been replaced with the updated value 2. See **Appendix AO.**

b) Please note that in Sheet I6, under the row of Weighting Factor - Billings, it indicates that the weighting value for Street Light class is 1.0 the same as a Residential customer. Based on the response in (a), please indicate whether the Weighting Factor for Street Light should be modified (eg. 12 bills to a single customer, but with a Weighting Factor larger than 1.0).

Response:

The "Weighting Factor – Billings" should not be modified. Once the corrections to the Cost Allocation Model are made in relation to a) above, the weighting factor of 1 will be correct.

Ontario Energy Board Interrogatory # 39

Ref: Exhibit 7 / Tab 2/ Schedule 1.0 – 2006 Cost Allocation Ratios

Based on the 2006 Cost Allocation Ratios, please provide a calculation of the revenue to cost ratio for each customer class that would be net of any transformer ownership allowance. In particular the following steps should be taken:

- Remove the "cost" associated with transformer ownership allowance from the revenue requirement (Worksheet I3);
- Calculate the revenue from each class at the 2006 approved rates, net of the transformer ownership allowance where applicable, and enter the revenues on worksheet I6, row 29; and,
- File Sheet O1 before and after removal of the transformer ownership allowance.

Response:

Table 1 below is Sheet O1 before the removal of the transformer ownership allowance.

Table 2 below is Sheet O1 after the removal of the transformer ownership allowance.

Table 1 – Before The Removal Of The Transformer Ownership Allowance

2006 COST ALLOCATION INFORMATION FILING

Hydro One Brampton Networks Inc.-Public
EB-2005-0377 EB-2006-0247
Monday, January 15, 2007

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street/Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$54,767,983	$28,776,061	$6,604,371	$8,205,886	$9,420,187	$1,488,124	$131,925	$141,428
mi	Miscellaneous Revenue (mi)	$3,008,438	$2,107,469	$325,579	$364,893	$159,370	$28,529	$15,169	$7,429
	Total Revenue	$57,776,421	$30,883,530	$6,929,950	$8,570,779	$9,579,557	$1,516,653	$147,094	$148,857
	Expenses								
di	Distribution Costs (di)	$6,106,158	$3,216,167	$554,820	$1,419,167	$569,519	$134,599	$187,287	$24,599
cu	Customer Related Costs (cu)	$4,669,323	$3,561,338	$555,617	$432,826	$79,224	$3,248	$27,693	$9,377
ad	General and Administration (ad)	$4,346,300	$2,733,497	$447,885	$747,109	$261,762	$55,627	$86,717	$13,704
dep	Depreciation and Amortization (dep)	$12,792,510	$6,354,232	$1,255,889	$3,025,203	$1,362,989	$342,195	$409,448	$42,554
INPUT	PILs (INPUT)	$10,240,872	$4,569,512	$976,851	$2,659,917	$1,415,188	$361,553	$230,465	$27,385
INT	Interest	$9,527,121	$4,251,034	$908,768	$2,474,531	$1,316,555	$336,354	$214,403	$25,477
	Total Expenses	$47,682,283	$24,685,780	$4,699,830	$10,758,753	$5,005,238	$1,233,575	$1,156,014	$143,095
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$10,094,138	$4,504,038	$962,854	$2,621,805	$1,394,911	$356,372	$227,163	$26,993
	Revenue Requirement (includes NI)	$57,776,421	$29,189,818	$5,662,684	$13,380,558	$6,400,149	$1,589,947	$1,383,177	$170,088
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$381,566,677	$180,834,241	$36,762,085	$94,905,140	$46,074,068	$11,597,894	$10,226,594	$1,166,656
gp	General Plant - Gross	$14,680,858	$6,853,063	$1,391,052	$3,689,085	$1,881,147	$476,737	$345,490	$44,284
accum dep	Accumulated Depreciation	($149,293,043)	($72,408,304)	($14,753,510)	($36,538,169)	($16,311,448)	($4,055,185)	($4,760,409)	($466,019)
co	Capital Contribution	($36,117,714)	($21,101,720)	($3,291,556)	($7,335,785)	($2,557,574)	($589,790)	($1,061,851)	($179,438)
	Total Net Plant	$210,836,778	$94,177,280	$20,108,072	$54,720,271	$29,086,192	$7,429,656	$4,749,824	$565,483
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$242,259,899	$71,011,168	$19,354,180	$73,059,386	$59,402,536	$17,512,414	$1,414,786	$505,429
	OM&A Expenses	$15,121,780	$9,511,002	$1,558,321	$2,599,102	$910,505	$193,474	$301,697	$47,680
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$257,381,679*	*$80,522,171*	*$20,912,501*	*$75,658,488*	*$60,313,041*	*$17,705,887*	*$1,716,483*	*$553,109*
	Working Capital	$38,607,252	$12,078,326	$3,136,875	$11,348,773	$9,046,956	$2,655,883	$257,472	$82,966
	Total Rate Base	$249,444,030	$106,255,605	$23,244,947	$66,069,044	$38,133,149	$10,085,539	$5,007,297	$648,449
		Rate Base Input equals Output							
	Equity Component of Rate Base	$112,249,814	$47,815,022	$10,460,226	$29,731,070	$17,159,917	$4,538,493	$2,253,284	$291,802
	Net Income on Allocated Assets	$10,094,138	$6,197,751	$2,230,120	($2,187,973)	$4,574,319	$283,078	($1,008,920)	$5,762
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$10,094,138	$6,197,751	$2,230,120	($2,187,973)	$4,574,319	$283,078	($1,008,920)	$5,762
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	105.80%	122.38%	64.05%	149.68%	95.39%	10.63%	87.52%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	$1,693,712	$1,267,266	($4,809,778)	$3,179,408	($73,294)	($1,236,083)	($21,231)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.99%	12.96%	21.32%	-7.36%	26.66%	6.24%	-44.78%	1.97%

Table 2 – After The Removal Of The Transformer Ownership Allowance

Ontario

2006 COST ALLOCATION INFORMATION FILING
Hydro One Brampton Networks Inc.-Public
EB-2005-0377 EB-2006-0247
Monday, January 15, 2007
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street/Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$53,299,708	$28,776,061	$6,604,371	$8,074,313	$8,383,469	$1,188,141	$131,925	$141,428
mi	Miscellaneous Revenue (mi)	$3,008,438	$2,107,504	$325,578	$364,855	$159,377	$28,533	$15,163	$7,429
	Total Revenue	**$56,308,146**	**$30,883,565**	**$6,929,949**	**$8,439,169**	**$8,542,846**	**$1,216,673**	**$147,087**	**$148,857**
	Expenses								
di	Distribution Costs (di)	$4,637,883	$2,463,591	$399,636	$981,440	$513,152	$134,599	$125,496	$19,969
cu	Customer Related Costs (cu)	$4,669,323	$3,561,338	$555,617	$432,826	$79,224	$3,248	$27,693	$9,377
ad	General and Administration (ad)	$4,346,300	$2,813,295	$446,076	$660,569	$276,715	$64,395	$71,546	$13,704
dep	Depreciation and Amortization (dep)	$12,792,510	$6,354,290	$1,255,888	$3,025,140	$1,363,000	$342,201	$409,437	$42,554
INPUT	PILs (INPUT)	$10,240,872	$4,570,281	$976,834	$2,659,083	$1,415,333	$361,637	$230,319	$27,385
INT	Interest	$9,527,121	$4,251,750	$908,752	$2,473,755	$1,316,689	$336,432	$214,267	$25,477
	Total Expenses	**$46,214,009**	**$24,014,545**	**$4,542,802**	**$10,232,812**	**$4,964,114**	**$1,242,513**	**$1,078,758**	**$138,465**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$10,094,138	$4,504,797	$962,837	$2,620,983	$1,395,053	$356,456	$227,019	$26,993
	Revenue Requirement (includes NI)	**$56,308,146**	$28,519,342	$5,505,639	$12,853,795	$6,359,167	$1,598,969	$1,305,777	$165,458
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$381,566,677	$180,849,714	$36,761,734	$94,888,360	$46,076,968	$11,599,594	$10,223,652	$1,166,656
gp	General Plant - Gross	$14,680,858	$6,854,001	$1,391,031	$3,688,067	$1,881,323	$476,840	$345,312	$44,284
accum dep	Accumulated Depreciation	($149,293,043)	($72,408,928)	($14,753,496)	($36,537,491)	($16,311,565)	($4,055,253)	($4,760,290)	($466,019)
co	Capital Contribution	($36,117,714)	($21,101,720)	($3,291,556)	($7,335,785)	($2,557,574)	($589,790)	($1,061,851)	($179,438)
	Total Net Plant	**$210,836,778**	**$94,193,067**	**$20,107,714**	**$54,703,150**	**$29,089,151**	**$7,431,391**	**$4,746,823**	**$565,483**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$242,259,899	$71,011,168	$19,354,180	$73,059,386	$59,402,536	$17,512,414	$1,414,786	$505,429
	OM&A Expenses	$13,653,506	$8,838,224	$1,401,328	$2,074,835	$869,092	$202,242	$224,735	$43,050
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$255,913,405***	***$79,849,393***	***$20,755,508***	***$75,134,221***	***$60,271,627***	***$17,714,656***	***$1,639,521***	***$548,479***
	Working Capital	$38,387,011	$11,977,409	$3,113,326	$11,270,133	$9,040,744	$2,657,198	$245,928	$82,272
	Total Rate Base	**$249,223,789**	**$106,170,476**	**$23,221,040**	**$65,973,283**	**$38,129,895**	**$10,088,589**	**$4,992,751**	**$647,755**
		Rate Base Input equals Output							
	Equity Component of Rate Base	$112,150,705	$47,776,714	$10,449,468	$29,687,978	$17,158,453	$4,539,865	$2,246,738	$291,490
	Net Income on Allocated Assets	$10,094,138	$6,869,020	$2,387,148	($1,793,643)	$3,578,732	($25,840)	($931,671)	$10,392
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	**$10,094,138**	**$6,869,020**	**$2,387,148**	**($1,793,643)**	**$3,578,732**	**($25,840)**	**($931,671)**	**$10,392**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	108.29%	125.87%	65.66%	134.34%	76.09%	11.26%	89.97%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	$2,364,223	$1,424,310	($4,414,626)	$2,183,679	($382,295)	($1,158,690)	($16,601)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	14.38%	22.84%	-6.04%	20.86%	-0.57%	-41.47%	3.56%

Ontario Energy Board Interrogatory # 40

Ref: Exhibit 7 / Tab 2/ Schedule 1.0 – 2011 Cost Allocation Ratios before Rebalancing

Please provide a calculation which uses the most recent approved distribution rates and the forecast of billing quantities in the test year. Provide an alternative calculation of 2011 revenue for each class, based on this calculation and prorated upwards or downwards (as applicable) to match the 2011 proposed revenue requirement. Enter the 2011 class revenues on worksheet I6, row 29, and file the model in excel format.

Response:

The response to this Interrogatory is based on Hydro Ones updated Cost Allocation Study for the 2011 Test Year after amendments based on Hydro One Brampton's filing of September 2, 2010. Hydro One Brampton has performed detailed Revenue Requirement, Rate Design and Cost Allocation calculations to make these updates.

Table 1 below provides the Costs Allocated by Customer Class. The column "Cost Allocated in Previous Cost Study" provides the cost by customer class that Hydro One Brampton's informational filing 2007 was based on after adjusting for the transformer ownership allowance related amounts which were excluded from the determination of the Revenue to Cost Ratios.

The "Cost Allocated in Test Year Study" provides the costs by customer class based on Hydro One Brampton's amended Cost Allocation Study for the 2011 Test Year. In addition, the 2011 Test Year Cost Allocation Study also excluded the impacts of the Transformer Ownership Allowance so that both sets of values are based on comparative Revenues and Costs. In Addition, the amounts in Columns A are based on Hydro One Brampton's updated Cost Allocation Study for the 2011 Test Year please refer to response to VECC IR #51 a. Table 4 and refer to sheet O1 which provides the Transformer Ownership Allowance corrected Revenue to Cost information and ratios.

Table 1 Cost Allocation – Allocated Cost

			Column A	
Classes	**Cost Allocated in Previous Study**	**%**	**Cost Allocated in Test Year Study**	**%**
Residential	28,519,342	50.65%	34,885,832	55.31%
GS < 50 kW	5,505,639	9.78%	5,813,786	9.22%
GS 50 to 699 kW	12,853,795	22.83%	13,020,552	20.64%
GS 700 to 4,999 kW	6,359,167	11.29%	5,381,677	8.53%
Large User	1,598,969	2.84%	2,034,651	3.23%
Street/Sentinel Lighting	1,305,777	2.32%	1,789,974	2.84%
Unmetered Scattered Load	165,458	0.29%	142,384	0.23%
Total	56,308,146		63,068,857	

Table 2 below provides the Revenues by Customer Class based on the 2011 Test Year Load forecast at:

Column B - Current OEB Approved Rates,
Column C - Current OEB Approved Rates prorated upward to match the proposed Revenue Requirement for the 2011 Test Year. The proration factor used to increase the Revenue by class

is 0.57% as shown below.
Column D – Proposed rates
Column E – Is the Proposed Miscellaneous Revenues by customer class as filed in this 2011 Cost of Service filing.

In Addition, the amounts in Columns D and E are based on Hydro One Brampton's updated Cost Allocation Study for the 2011 Test Year please refer to **Appendix AO** and refer to sheet O1 which provides the applied for Revenue to Cost information and ratios.

Table 2 Cost Allocation – Calculated Class Revenues

	Column B	Column C	Column D	Column E
Classes	**L.F. X Current Approved rates**	**L.F. X existing rates X (1+V.)**	**L.F. X proposed rates**	**Miscellaneous Revenue**
Residential	32,789,200	32,977,678	32,514,987	2,763,164
GS < 50 kW	7,094,795	7,135,577	6,565,989	410,554
GS 50 to 699 kW	8,766,656	8,817,049	9,900,516	515,926
GS 700 to 4,999 kW	7,861,958	7,907,150	6,821,866	174,315
Large User	1,935,357	1,946,482	1,946,273	88,378
Street/Sentinel Lighting	194,594	195,712	1,226,752	26,230
Unmetered Scattered Load	102,209	102,797	106,062	7,845
Total	58,744,770	59,082,445	59,082,445	3,986,412
Revenue Deficiency		337,676	I.	
Distribution Revenue		58,744,770	II.	
Other Operating Revenue (Net)		3,986,412	III.	
		63,068,857	IV.	
V. = I./II.		0.57%	V.	

Table 3 below provides a comparison of the following Revenue to Cost Ratios:

a) Previously Filed Ratios – Filed with the Board in 2007 assuming no adjustment to Transformer Ownership Allowance. (see response to OEB IR 39 for O1 sheet)

b) Status Quo Ratios - Are Revenue to Cost ratios assuming no change (see response to VECC # 51 a. Table 4 for O1 sheet).

c) Proposed Ratios – Are the Revenue to Cost ratios submitted by Hydro One Brampton to rebalance rates to bring the Revenue to Cost ratios closer to unity. **(Appendix AS).**

Table 3 Cost Allocation - Re-balancing Revenue-to-Cost Ratios

Classes	Previously Filed Ratios	Status Quo Ratios	Proposed Ratios
	Most Recent Year 2006	=(Column C + Column E) / (Column A)	=(Column D + Column E) / (Column A)
Residential	105.80%	102.45%	101.12%
GS < 50 kW	122.38%	129.80%	120.00%
GS 50 to 699 kW	64.05%	71.68%	80.00%
GS 700 to 4,999 kW	149.68%	150.17%	130.00%
Large User	95.39%	100.01%	100.00%
Street/Sentinel Lighting	10.63%	12.40%	70.00%
Unmetered Scattered Load	87.52%	77.71%	80.00%

Ontario Energy Board Interrogatory # 41

Exhibit 8 / Tab 2/ Schedule 1.0 – Fixed and Variable Revenue Allocation

Response:

Hydro One Brampton has submitted updated Cost of Service application models and its Revenue Requirement, Cost Allocation and Rate Design models have been filed with these Interrogatories. The monthly service charge rate for the Large User class has now been increased from $4,722.21 to $4,748.97; in addition, the proposed volumetric distribution rate for the Large User class was reduced from $2.9023/kW to $2.3003/kW. Furthermore, the volumetric transformer ownership allowance was been reduced (eliminated) from $0.60/kW to $0.00/kW.

The analysis provided below in Table 1 demonstrates that the Fixed/Variable Distribution Revenue Split remains the same under both Existing Rates and at Proposed Rates. When calculating the split the transformer ownership allowance must be taken into consideration, as its elimination effectively must be netted with the variable distribution revenue. Previously the Large User class received a transformer ownership allowance, but based on the results of the Cost Allocation Study, the transformer ownership allowance was eliminated and the volumetric distribution rate was reduced because of this as well. Hydro One Brampton submits that there is no change to the Fixed and Variable Revenue proportions based on the proposed distribution rates.

Table 1 Fixed/Variable Distribution Revenue Proportions

	Fixed Distribution Revenue	Variable Distribution Revenue			Total Revenue
		Variable Rate	Transformer Allowance	Net Variable Revenue	
Fixed Variable Split At Existing Rates:					
Large User Class - Distribution Revenue	$ 340,008	$ 2,013,820	$ (418,471)	$ 1,595,349	$ 1,935,357
Fixed Variable Split	17.57%	104.05%	-21.62%	82.43%	100.00%
Fixed Variable Split At Proposed Rates:					
Large User Class - Distribution Revenue	$ 341,926	$ 1,604,347	$ -	$ 1,604,347	$ 1,946,273
Fixed Variable Split	17.57%	82.43%	0.00%	82.43%	100.00%

Ontario Energy Board Interrogatory # 42

Ref: Exhibit 8 / Tab 6/ Schedule 4.0/ Page 2 – Bill Impact Exhibit 7/ Tab 2/ Schedule 1.0

a) The Total Bill Impact for Street Lights is 48.72% as compared to 2010.

Please explain why Hydro One Brampton did not propose a phase-in approach to mitigate the bill impacts for the Street Light class.

Hydro One Brampton has updated its Cost of Service rate application model due to the filing of September 2, 2010. Due to the revision to Revenue Requirement, the Cost Allocation model and Rate Design models have been updated. The distribution rates have changed for all classes and the total bill impact for the Street Light class has now becomes 31.33%. Hydro One Brampton chose not to propose a phase-in approach to mitigate the bill impact for the Street Light Class nor any other customer class. Hydro One Brampton's approach for establishing revenue to cost ratios was where the revenue to cost ratio was outside the OEB established bands, that the revenue to cost ratio would be adjusted to the closest upper or lower limit of the band, whatever the case may be. Where the Revenue to Cost Ratio was inside the band, Hydro One Brampton adjusted the revenue to cost ratio to move closer to unity.

b) Please provide a calculation of the revenue to cost ratio for the GS 700 – 4999 kW class that would result if the ratio for the Street Light class is lower than proposed, such that the revenue to cost ratio for the Street Light class is 45%, and the rate for the GS 700 - 4999 kW class is higher than proposed so that it compensates for the lower revenue from the Street Light class.

See Table 1 below shows the revenue to cost ratio in this hypothetical adjustment, and Table 2 below shows the resulting monthly service charge and the volumetric distribution rate. The revenue to cost ratio for the Street Light Class was set to 45% and the resulting revenue to cost ratio for the General Service > 700 kW to 4,999 kW is 138.32%.

c) Please provide a calculation of the bill impacts for the Street Light class and a representative customer in the GS 700 – 4999 kW class resulting from the hypothetical rates in part b.

Table 3 provides the bill impact for a representative Street Light Class customer. The total bill impact for this customer is 17.76% after adjusting the revenue to cost ratio. Table 4 provides the bill impact for a representative customer in the General Service > 700 kW to 4,999 kW class. The bill impact for this customer is (0.18%).

Table 1 Cost Allocation Revenue/Cost Ratio Adjustments

Class	Costs Allocated from Cost Allocation	2011 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from Cost Allocation	Total Revenue	Revenue Cost Ratio	Check Revenue/ Cost Ratios from Cost Allocation	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	34,885,832	32,977,678	2,763,164	35,740,842	102.45%	101.12%	101.12%	35,278,151	2,763,164	32,514,987
GS < 50 kW	5,813,786	7,135,577	410,554	7,546,131	129.80%	120.00%	120.00%	6,976,544	410,554	6,565,989
GS > 50 kW to 699 kW	13,020,552	8,817,049	515,926	9,332,975	71.68%	80.00%	80.00%	10,416,441	515,926	9,900,516
GS > 700 kW to 4,999 kW	5,381,677	7,907,150	174,315	8,081,465	150.17%	138.32%	138.32%	7,443,674	174,315	7,269,359
Large Use	2,034,651	1,946,482	88,378	2,034,860	100.01%	100.00%	100.00%	2,034,651	88,378	1,946,273
Street Lighting	1,789,974	195,712	26,230	221,942	12.40%	45.00%	45.00%	805,488	26,230	779,258
Unmetered Scattered Load	142,384	102,797	7,845	110,642	77.71%	80.00%	80.00%	113,908	7,845	106,062
TOTAL	**63,068,857**	**59,082,445**	**3,986,412**	**63,068,857**	**100.00%**			**63,068,857**	**3,986,412**	**59,082,445**
	63,068,857									59,082,445
	-	Check total - must be zero							This must be zero	0

Table 2 Distribution Rate Calculations

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Resulting Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	32,514,987	55.03%	$10.51	$0.0153	$ 15,595,996	$ 16,918,991		32,514,987	0	32,514,987
GS < 50 kW	6,565,989	11.11%	$18.76	$0.0165	$ 1,776,862	$ 4,789,127		6,565,989	0	6,565,989
GS > 50 kW to 699 kW	9,900,516	16.76%	$114.83	$2.5804	$ 2,138,888	$ 7,761,628	$ 185,754	10,086,269	0	10,086,269
GS > 700 kW to 4,999 kW	7,269,359	12.30%	$1,304.14	$3.7066	$ 1,658,135	$ 5,611,224	$ 1,354,100	8,623,460	0	8,623,460
Large Use	1,946,273	3.29%	$4,748.97	$2.3003	$ 341,926	$ 1,604,347	$ -	1,946,273	0	1,946,273
Street Lighting	779,258	1.32%	$0.26	$7.3076	$ 131,534	$ 647,725		779,258	0	779,258
Unmetered Scattered Load	106,062	0.18%	$1.00	$0.0185	$ 15,605	$ 90,458		106,062	0	106,062
TOTAL	**59,082,445**	**100.00%**			**$ 21,658,944**	**$ 37,423,501**	**$ 1,539,854**	**$ 60,622,299**	**$ -**	**$ 60,622,299**
			Forecast Fixed/Variable Ratios		**35.728%**	**61.732%**	**2.540%**	**100.000%**		
			Fixed/Variable Split excluding SL		21,527,411	36,775,776	1,539,854	59,843,041		
			Fixed/Variable Split %		35.973%	64.027%				

Table 3 Street Light Class Bill Impacts

Street Lighting

Billing Determinants
6,677 Connections
417,140 kWh
1,106 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	6,677	0.00	0.00	6,677	0.26	1,736.02	1,736.02	100.00%	3.14%
Distribution (kWh)	417,140	0.0000	0.00	417,140	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	1,106	2.2046	2,438.29	1,106	7.3076	8,082.21	5,643.92	231.47%	14.61%
Regulatory Assets Rider #1 (kW)	1,106	(0.6678)	(738.59)	1,106	(0.6678)	(738.59)	0.00	0.00%	(1.33%)
Regulatory Assets Rider #2 (kW)	1,106	0.0000	0.00	1,106	0.1433	158.49	158.49	0.00%	0.29%
Global Adjustment Disposition Rider (kW)	1,106	0.4461	493.39	1,106	0.4461	493.39	0.00	100.00%	0.89%
Sub-Total			**2,193.09**			**9,731.52**	**7,538.43**	**343.74%**	**17.59%**
Other Charges (kWh)	431,990	0.0136	5,890.81	431,698	0.0136	5,886.83	(3.98)	(0.07%)	10.64%
Other Charges (kW)	1,106	3.1871	3,524.93	1,106	3.0690	3,394.31	(130.62)	(3.71%)	6.13%
Cost of Power Commodity (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.00%	0.09%
Cost of Power Commodity (kWh)	431,240	0.0694	29,919.44	430,948	0.0694	29,899.19	(20.26)	(0.07%)	54.04%
Total Bill Before Taxes			**41,580.31**			**48,963.88**	**7,383.57**	**17.76%**	**88.50%**
HST		13.00%	5,405.44		13.00%	6,365.30	959.86	17.76%	11.50%
Total Bill			**46,985.75**			**55,329.18**	**8,343.43**	**17.76%**	**100.00%**

Table 4 General Service > 700 kW to 4,999 kW

GENERAL SERVICE > 700 kW to 4,999 kW

Consumption
800,000 kWh
2,000 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			1,410.45			1,304.14	(106.31)	(7.54%)	1.37%
Distribution (kWh)	800,000	0.0000	0.00	800,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	2,000	3.7355	7,471.00	2,000	3.7066	7,413.20	(57.80)	(0.77%)	7.80%
Smart Meter Rider (per month)			1.00			1.55	0.55	55.00%	0.00%
Transformer Credit	2,000	(0.6000)	(1,200.00)	2,000	(0.7048)	(1,409.60)	(209.60)	17.47%	(1.48%)
LRAM & SSM Rider (kW)	2,000	0.0000	0.00	2,000	0.0378	75.60	75.60	0.00%	0.08%
Regulatory Assets Rider #1 (kW)	2,000	(0.8881)	(1,776.20)	2,000	(0.8881)	(1,776.20)	0.00	0.00%	(1.87%)
Regulatory Assets Rider #2 (kW)	2,000	0.0000	0.00	2,000	0.2501	500.20	500.20	0.00%	0.53%
Global Adjustment Disposition Rider (kW)	2,000	0.5881	1,176.20	2,000	0.5881	1,176.20	0.00	100.00%	1.24%
Sub-Total			**7,082.45**			**7,285.09**	**202.64**	**2.86%**	**7.66%**
Other Charges (kWh)	828,480	0.0136	11,297.52	827,920	0.0136	11,289.88	(7.64)	(0.07%)	11.87%
Other Charges (kW)	2,000	4.2141	8,428.20	2,000	4.0596	8,119.20	(309.00)	(3.67%)	8.54%
Cost of Power Commodity (kWh)	828,480	0.0694	57,479.94	827,920	0.0694	57,441.09	(38.85)	(0.07%)	60.42%
Total Bill Before Taxes			**84,288.11**			**84,135.26**	**(152.85)**	**(0.18%)**	**88.50%**
HST		13.00%	10,957.45		13.00%	10,937.58	(19.87)	(0.18%)	11.50%
Total Bill			**95,245.56**			**95,072.84**	**(172.72)**	**(0.18%)**	**100.00%**

Ontario Energy Board Interrogatory # 43

Ref: Exhibit 8 / Tab 3/ Schedule 1.0/ Page 1 – Retail Transmission Service Rates (RTSR)

In its Revised Guideline G-2008-0001, issued on July 8, 2010, the Board has described the evidence required for RTSRs, which includes completion of a model that was provided by Board staff on August 20, 2010. Please complete and file the model. If the rates that result from the model are different from the ones proposed by Hydro One Brampton in the original application, please clarify which rates Hydro One Brampton wishes to propose and why.

Response:

Hydro One Brampton has completed the model that was provided by Board staff on August 20, 2010. The results, as a result of running this model, are different than the ones that Hydro One Brampton submitted in its rate application of June 30, 2010. Hydro One Brampton requests that the OEB approve the rates that were generated as a result of this latest model. These rates are summarized below. In addition, Hydro One Brampton has supplied a copy of the model in **Appendix AS**

Hydro One Brampton's Proposed 2011 RTSR's

Customer Class	Current		Proposed	
	RTSR - Network	RTSR - Connection	RTSR - Network	RTSR - Connection
Residential	$ 0.0061	$ 0.0051	**$ 0.0060**	**$ 0.0048**
General Service Less Than 50 kW	$ 0.0055	$ 0.0044	**$ 0.0054**	**$ 0.0041**
General Service 50 to 699 kW	$ 2.1307	$ 1.6973	**$ 2.0895**	**$ 1.5966**
General Service 700 to 4,999 kW	$ 2.3896	$ 1.8245	**$ 2.3433**	**$ 1.7163**
Large Use > 5000 kW	$ 2.7045	$ 2.1088	**$ 2.6522**	**$ 1.9837**
Unmetered Scattered Load	$ 0.0055	$ 0.0044	**$ 0.0054**	**$ 0.0041**
Sentinel Lighting	$ 1.7764	$ 1.4148	**$ -**	**$ -**
Street Lighting	$ 1.7741	$ 1.4130	**$ 1.7398**	**$ 1.3292**

Ontario Energy Board Interrogatory # 44

Ref: Exhibit 8/ Tab 5/ Schedule 1.1/ Page 2 / Table 1

The Applicant calculates the Supply Facilities Loss Factor (SFLF) based on the

Wholesale kWh delivered to distributor values A1 and A2 in Table 1. With respect to A1 and A2, please confirm and explain whether:

a) The A1 value refers to the defined/deemed metering point on the primary side of Hydro One's Transmission's transformer; and

b) The A2 value refers to the physical metering installation on the secondary side of Hydro One's Transmission's transformer. Further in Exhibit 8/ Tab 5/ Schedule1/ page 1, the Applicant states that Hydro One Brampton is supplied from delivery points on the transmission system with the exception of one feeder whereby Hydro One Brampton is an embedded LDC from a supply perspective. Please explain whether or not the embedded aspect has been factored in the calculation of the SFLF in Table 1.

Response:

Hydro One Brampton confirms that the A1 values refer to the defined/deemed metering point on the primary side of the transmission transformer.

Hydro One Brampton confirms that the A2 values refer to the physical metering installation on the secondary side of the transmission transformer.

With respect to the feeder whereby Hydro One Brampton is an embedded LDC, from a supply perspective Hydro One Brampton purchases power from and settles with the IESO rather than from the Host Distributor. The settlements associated with energy purchased are dealt with using the same methodology as is used for the non-embedded delivery points. There is no embedded aspect that needs to be factored into the calculation of the SFLF

Ontario Energy Board Interrogatory # 45

Ref: Exhibit 8/ Tab 5/ Schedule 1.1/ Page 3 / Table 2

The Applicant provides distribution loss factors (DLF) and total loss factors (TLF) in Table 2 for customers less than 5,000 kW and greater than 5,000 kW. In deriving the TLFs from the DLFs , the Applicant uses a SFLF of 1.0025 for customers less than 5,000 kW, and a SFLF of 1.0045 for customers greater than 5,000 kW. Please explain why two different SFLFs have been used for customers greater than and less than 5,000 kW rather than one SFLF for all customers per industry practice.

Response:

Hydro One Brampton proposes using the default SFLF of 1.0045 for the Large User class as Hydro One Brampton submits that this factor is more representative of the losses associated with this class. The SFLF of 1.0025 represents all losses associated with the transformer station only. Since every Large User is supplied by distribution lines, the losses associated with these lines must be factored in. The SFLF of 1.0025 does not, by definition, include any allowances for these losses associated with the distribution lines. Hydro One Brampton therefore submits that this default factor of 1.0045 would be the minimum to be used as the SFLF and that the Distribution System SFLF of 1.0025 would be inadequate to recover losses for this class of customers.

Ontario Energy Board Interrogatory # 46

Ref: Exhibit 9 / Tab 3 / Schedule 1.0 – Smart Meter

Please confirm whether all the smart meter costs incurred to the end of December 2009 as stated in this application have been audited. If not, please explain why.

Response:

KPMG has audited the Company's financial statements for the year ended December 31, 2009.

Ontario Energy Board Interrogatory # 47

Ref: Exhibit 9 / Tab 3 / Schedule 1.1 – Total Cost per Smart Meter

On page 4 Table 2, the Total Cost per Smart Meter for the period from 2006 to 2009 is $175.69. On the same page Table 3, the Total Cost per Smart Meter for the period from 2006 to 2011 is $252.05.

Please provide an explanation for the increase in total cost per smart meter for the smart meters to be deployed in 2010 & 2011 compared with the costs of smart meters installed from 2006 to 2009.

Tables 2 and 3 were prepared based on the annual accounting information. However when comparing the total unit costs between the two time periods reallocations of costs are necessary so that the costs are reflective of the number of smart meters installed to the end of 2009. Costs were recognized for accounting purposes in 2010 and 2011 that relate to installations of smart meters to the end of 2009. Hydro One Brampton has reallocated these costs. Much of the OM&A & Depreciation costs relate to smart meters installed until 2009, in addition the bulk of costs transferred to capital from work in process in 2010 relate to smart meters installed up to 2009, the proceeding costs were re-allocated.

As a result, HOBNI has provided the following table entitled "Summary of Reallocated Smart Meter Costs – 2006 to 2011" below for more detail. This table better describes the total costs per meter for the whole Smart Metering program.

Summary of Reallocated Smart Metering Costs 2006 to 2011

	2006 to 2009	2006 to 2011
Total Capital Cost	20,641,028	25,562,585.00
Total OM&A and Depreciation	7,363,427	8,107,191.53
Number of Smart Meters Installed	125,192	133,582
Capital Cost per Smart Meter	164.87	191.36
OM&A and Depreciation Costs per Smart Meter	58.82	60.69
OM&A Cost per Smart Meter net of Depreciation	21.69	21.47
Total Cost per Smart Meter	223.69	252.05

Revised Total Cost per Smart Meter

As per the above, the adjusted cost per Smart Meter to the end of 2009, including adjustments for costs in 2010 and 2011, is $223.69. The cost per Smart Meter for the entire program (2006 to 2011) remains $252.05.

The following adjustments were made to Tables 2 and 3.

Capital Costs

Capital costs reported in 2010 included an amount for Smart Metering Capital IT Development totaling $808,925.46. These costs are expected to materialize in 2010 however, they will be applicable to all smart meters, not only those installed in 2010. In order to match costs to installed meters, Hydro One Brampton adjusted the capital costs for each period based on the number of meters installed each year.

OM&A Costs

OM&A costs reported in 2010 were prorated based on the number of meters installed to the end of 2010. The Company installed a total of 125,192 smart meters in 2009 and 7,405 in 2010. The

proration rates applied were 94.42% and 5.58%. The 2011 OM&A costs were apportioned as follows: 93.72% to smart meters installed to the end of 2009; 5.54% for 2010 and; 0.74% for 2011 installations. Similar allocations were done for Depreciation costs. Please refer to the following table titled Reallocated Smart Meter Costs – 2006 to 2011 for details.

Ontario Energy Board Interrogatory # 48

Ref: Exhibit 9 / Tab 3 / Schedule 1.1 – Proposed Disposition Rate Rider

Board staff notes that in the Board's Decision (EB-2007-0882), it stated that "Hydro One Brampton requested a -$0.09 per metered customer per month rate rider to true-up the 2006 and 2007 revenue requirement (i.e., cost of capital and depreciation) associated with the approved smart meter expenditures (EB-2007-0063) with amount collected by its smart meter rate adder from May 2006 through April 2007."

In Exhibit 9/ Tab 3/ Schedule 1.1/ page 5, Hydro One Brampton is requesting a disposition rate rider of $0.36 per customer, per month to recover the difference between the revenue entitlement and the amount collected to the end of 2009.

a) Please clarify the relationship between the proposed disposition rate rider and the $0.09 rate rider reference above.

Response:

The ($0.09) rate rider referenced above was approved as a true up of the revenue entitlement for Hydro One Brampton's investment in Smart Meters to the end of April 2007. The true up was calculated as the difference between amounts collected by Hydro One Brampton through funding adders and the allowable revenues for the Smart Meter investments for this time period. Hydro One Brampton acknowledges that it must make adjustment to its calculations for the $0.36 per customer disposition rider for the true up of revenue entitlement to the end of December 31, 2009. The disposition rider currently being requested included the investment and related funding adder amounts that were previously trued up until April 2007.

b) Please recalculate the proposed disposition rate rider by excluding any costs that previously have been approved by the Board.

Hydro One Brampton has recalculated the proposed disposition rate rider and excluded costs that were previously approved by the Board. The table below provides the revised revenue requirement, amount collected and the disposition rate rider. Please see **Appendix O** for more detail calculation.

2011 Smart Meter Rate Rider Application

Final Disposition Rider

Revenue Requirement:	
2006 Rate Year Entitlement	-
2007 Rate Year Entitlement	343,540
2008 Rate Year Entitlement	1,115,769
2009 Rate Year Entitlement	2,526,775
	3,986,083
Smart Rate Rider Billed:	
2006 Rate Year Billed May 1/06 - April 30/07	-
2007 Rate Year Billed May 1/07 - April 30/08	(964,337)
2008 Rate Year Billed May 1/08 - April 30/09	(978,674)
2009 Rate Year Billed May 1/09 - Dec 31/09	(1,191,228)
	(3,134,239)
Smart Meter Costs for Recovery	851,845
Forecasted Number of Customers	132,427
Number of Months	12
Disposition Rate Rider	0.54

Ontario Energy Board Interrogatory # 49

Ref: Harmonized Sales Tax

The PST and GST were harmonized effective July 1, 2010. Historically, unlike the GST, the PST was included as an OM&A expense and was also included in capital expenditures. Due to the harmonization of the PST and GST, regulated utilities may benefit from a reduction in OM&A expenses and capital expenditures on an actual basis.

a) Please state whether or not the applicant has adjusted its Test Year revenue requirement to account for reductions to OM&A expense and capital expenditures that the applicant may realize due to the implementation of the HST effective July 1, 2010. If yes, please identify separately the amounts for OM&A and capital and provide an explanation of how each of those amounts was derived. If no, please identify the amounts in OM&A expense and capital expenditures for the Test Year that were previously subject to PST and are now subject to HST.

Response:

HOBNI's OM&A and capital expenditures reflect expected actual costs. The estimated amounts that OM&A and capital expenditures would have been reduced by can be derived as follows:

(in thousands)	2009 Inventory issues A	PST included in 2009 B = A x 8/108	2009 Total C	PST as a % of 2009 Total D = B/D	2011 Test Total E	PST included in 2011 F = D * E
OM&A	698	52	17,836	0.29%	25,307	73
Capital expenditures	11,636	862	33,294	2.59%	20,984	543

b) The Board's decision on most 2010 IRM applications established a deferral account and directed applicants to record the incremental input tax credits it receives on distribution revenue requirement items that were previously subject to PST and which become subject to HST. Tracking of these amounts would continue in the deferral account until the effective date of the applicant's next cost of service rate order. Please provide a detailed explanation of how Hydro One Brampton is currently tracking these amounts.

Response:

HOBNI is tracking reductions in OM&A and the impact of reductions in capital expenditures consistent with the Hydro One Corporate approach. This involves estimating the amount of PST costs in 2010 revenue requirement that will not be incurred after July 1, 2010. Then, 50% of this amount is recorded in a deferral account (USofA 1592) for future disposition.

Ontario Energy Board Interrogatory # 50

Ref: Low Income Energy Assistance Program (LEAP)

Please state whether or not the applicant has included an amount in its 2011 Test year revenue requirement for the LEAP emergency assistance program.

a) If yes, please identify the amount.

Response:

Hydro One Brampton has not included an amount for the LEAP Emergency Assistance Program

b) If no, please provide the following calculation: 0.12% of the total distribution revenue proposed by the applicant for the 2011 Test Year.

Response:

Total Distribution Revenue 62,721,985 X .0012 = 75,266

c) Please state whether or not the applicant has included an amount in its 2011 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

Response:

No revenue requirements for legacy programs have been included.

Ontario Energy Board Interrogatory # 51

Ref: Ontario Municipal Employees Retirement System Pension Costs

Hydro One Brampton filed a letter, dated September 2, 2010, providing certain updates to its application. In the letter, Hydro One Brampton stated that a recent announcement by OMERS an increase to pension plan contributions. for the years, 2011, 2012, and 2013. Hydro One Brampton also stated that the increases in contributions are material and expected to be approximately $1.0 million for this time period. Please provide the forecasted increase of the OMERS expense by years and the documentation to support the increases.

Response:

The forecasted increase of the OMERS expense by years is as follows:

			Year 2010	Year 2011	Year 2012	Year 2013
Prior year	A		$ 14,850,189	$ 15,295,695	$ 15,754,566	$ 16,227,203
Wage inflation	B	3%	$ 445,506	$ 458,871	$ 472,637	$ 486,816
Total earnings	C = A*B		$ 15,295,695	$ 15,754,566	$ 16,227,203	$ 16,714,019
OMERS % increase	D			1.00%	2.00%	2.90%
Incremental premiums	E=C*D			$ 157,546	$ 324,544	$ 484,707
Incremental premiums (in millions)				$ 0.2	$ 0.3	$ 0.5

The OMERS employer update of September 10, 2010 confirmed the three-year contribution rate increases (**See Appendix P**)

Ontario Energy Board Interrogatory # 52

Ref: Exhibit 1, Tab , Schedule 3.1 – Revenue Requirement Work Form

a) Based on the responses to the interrogatories from all parties, please submit an updated Microsoft Excel file containing the revenue requirement work form.

Response:

Hydro One Brampton has submitted the Revenue Requirement Work Form. See **Appendix AX**

b) Please provide a listing of all changes made to Hydro One Brampton's original application (by exhibit), including an updated derivation of its revenue requirement, PILs calculation, base rates, rate adders/riders, and bill impacts.

Response: Hydro One Brampton submits the following updated models:

Appendix AO – Cost Allocation Model – Applied For

Appendix AR – Distribution Revenue Throughputs Model

Appendix AS – Rate Design Model – Applied For

Appendix AV – Revenue Deficiency Model

Appendix AW – Revenue Requirement Model

Appendix AX – Revenue Requirement Work Form

Information submitted in the June 30, 2010 application has been superseded through the submissions of the models noted above or through responses to Interrogatories:

Exhibit 2 Rate Base - Changes as shown in Appendix AW

Exhibit 3 Operating Revenue – Changes as shown in Appendix AW and AR

Exhibit 4 Operating Costs – Changes as shown in Appendix AW

Exhibit 5 Cost of Capital & Rate of Return – Changes as shown in Appendix AW

Exhibit 6 Calculation of Revenue Deficiency – Changes as shown in Appendix AV

Exhibit 7 Cost Allocation – Changes as shown in Appendix AO

Exhibit 8 Rate Design – Changes as shown in AS

Exhibit 9 Deferral and Variance Accounts – Updates to Exhibit 1 Tab 1

Exhibit 11 – All models previously submitted have been re-submitted

Ontario Energy Board Interrogatory # 53

Ref: Responses to Letter of Comment

c) Following publication of the Notice of Application, did Hydro One Brampton receive any letters of comment?

Response:

Hydro One Brampton did not receive any letters of comment regarding its rate application.

d) If so, please confirm whether a reply was sent from Hydro One Brampton to the author of the letter. If confirmed, please file that reply with the Board.

Response:

Not Applicable.

e) If not confirmed, please explain why a response was not sent and confirm if Hydro One Brampton intends to respond.

Response:

Not Applicable.

Ontario Energy Board Interrogatory # 54

Ref: Exhibit 9/ Tab 1/ Schedule 3.0/ Page 1-9 – New Account request

Hydro One Brampton is requesting a new deferral and variance account for

Costs Subsequent to IFRS Implementation.

The Board report EB-2008-0408 dated July 28, 2009 "Transition to International Financial Reporting Standards" (Appendix 2, article 8.2) states:

"The Board will establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS. This account is exclusively for necessary, incremental transition costs, and is not to include ongoing compliance costs or impacts on revenue requirement arising from changes in the timing of the recognition of expenses."

a) Is the proposed account expected to record any costs specifically excluded in the Board report EB-2008-0408 (i.e. ongoing compliance costs or impacts on revenue requirement arising from changes in timing of the recognition of expenses)?

Response:

No

b) What is the regulatory precedent for costs proposed to be included in this deferral account?

Response:

An OEB-approved precedent can be found in Hydro One Networks Inc. Distribution case (EB-2009-0069).

c) What is the justification for this account?

Response:

The account is requested to record the aggregate impact on the 2011 revenue requirement resulting from any changes to existing IFRS standards or changes in the interpretation of such standards. Interpretation changes would include those originating with the International Accounting Standards Board or any of its arms (e.g. the International Financial Reporting Interpretations Committee or IFRIC), the professional accounting community including the large international accounting firms, and the Board or its Staff in terms of the application of modified IFRS for regulatory purposes. The account is to permit Hydro One Brampton to record, for future disposition, those revenue requirement impacts resulting from IFRS changes that arise before the next cost of service proceeding.

d) What account number does Hydro One Brampton propose to use in the USoA?

Response:

Hydro One Brampton would use Account 1508 Other Regulatory Assets, Sub Account Impact of Changes in IFRS.

e) What are the journal entries to be recorded?

Response:

Hydro One Brampton cannot reasonably predict specific entries that would result from future changes in IFRS accounting standards or from changes in external interpretations of IFRS standards. In general, increases in revenue requirement attributable to such changes would be

debited to the account and decreases would be credited.

f) Please provide Hydro One Brampton's estimate of the quantum of the costs that would be recorded in this account.

Response:

Given that the account is meant to capture the impact of unforeseeable accounting changes, Hydro One Brampton does not currently have any reasonable basis to estimate possible impacts.

g) If the costs are not known, what would be the basis of the approval to record these amounts in a deferral account?

Response:

As these are contingent costs/gains that could result from future IFRS changes or interpretation changes by third parties, the revenue requirement impact cannot reasonably be identified or estimated at this time. As such, a symmetrical variance account would appear to be an ideal mechanism to capture the costs for future Board review.

h) What new or additional information is available since the June 30, 2010 filing of this application that would improve the Board's ability to make a decision on this request?

Response:

In its September 7 & 8, 2010 meetings, the Canadian Accounting Standards Board (AcSB) approved a one year optional IFRS implementation delay for publicly accountable rate regulated utilities subject to cost of service regulation. This means that such utilities must adopt IFRS by January 1, 2012, rather than January 1, 2011.

On September 16, 2010, the IASB decided to continue its rate regulated accounting project but it did not make a decision whether this would be done through a medium term project focused on rate regulation or a long term project covering intangibles in general. This decision will be made through future agenda setting efforts entailing public comment. It appears highly unlikely that a rate regulated accounting decision will be made in time for the new 2012 deadline for utilities to implement IFRS.

Given that Hydro One Brampton will likely take the deferral option, this variance account will likely not be required for 2011.

Ontario Energy Board Interrogatory # 55

Ref: Exhibit 9/ Tab 1/ Schedule 3.0/ Page 1-9 – New Account request

Hydro One Brampton is requesting a new deferral and variance account for Losses on Early Retirements.

a) Please provide an estimate of the costs that would be recorded in this account.

Response:

Hydro One Brampton has requested this account because it cannot reasonably forecast the losses to be incurred upon premature asset retirements under IFRS.

b) Please provide an estimate of the impact on the revenue requirement going forward indicating at a minimum the directional impact, based on historical experience and other analysis.

Response:

While the amount of losses cannot reasonably be quantified or estimated within a range, Hydro One Brampton expects that it is reasonably likely that it will incur net losses that are material enough to be considered for deferral and future recovery. While gains and losses on sale would also be posted to this account, it is expected that sufficient net losses from premature retirements will be incurred under IFRS to make it probable that the account would generally be in a debit position. These losses would be recorded in this proposed account to allow for future review and recovery from customers.

c) If the costs are not known, what is the basis for the approval to record these amounts in a deferral account?

Response:

In the absence of an approved deferral account to record such net premature asset losses, all such losses that were not included in revenue requirement on a forecast basis would be charged to the shareholder. This would unfairly burden the shareholder with accounting losses that Hydro One Brampton is not reasonably able to predict or in many cases control. For example, assets replaced as a result of storm activity, municipal road widenings or customer upgrade requests can retire earlier than expected, thus resulting in accounting losses under IFRS. Losses on premature retirement need to be recovered to ensure full capital recovery of prudently installed fixed and intangible assets.

d) What account number does Hydro One Brampton propose to use in the USoA for this account?

Response:

Hydro One Brampton would use Account 1508 Other Regulatory Assets, Sub Account Net Losses on Asset Premature Retirements.

e) What are the journal entries to be recorded?

Response:

If a loss is recorded in the IFRS Statement of Operations:

Debit: 1508 Net Losses on Asset Premature Retirements

Credit: 4360 Loss on Disposition of Utility and Other Property

If a gain is recorded in the IFRS Statement of Operations:

Debit: 4355 Gain on Disposition of Utility and Other Property

Credit: 1508 Net Losses on Asset Premature Retirements

f) What is the justification for this account?

Response:

This account would have held any gains and losses resulting from asset sales, and losses resulting from premature asset component retirements, recorded after IFRS adoption effective January 1, 2011. Under IFRS, such gains and losses cannot reasonably be forecast. As a result, a deferral account is required to provide a mechanism to allow net gains and losses to be included in rates and to allow for capital recovery. Prior to the adoption of IFRS, most "losses" on premature retirement incurred by Hydro One Brampton were charged to accumulated depreciation on the balance sheet and were recovered within future depreciation expense. Under IFRS, such losses are recorded in the Statement of Operations. Unless a deferral account is approved, net gains and losses will be to the shareholder's account as it is problematic to include a reasonable estimate in the calculation of the revenue requirement.

g) What is the regulatory precedent for costs proposed to be included in this deferral account?

Response:

Hydro One Brampton is not aware of an approved precedent, although Hydro One Networks Inc. Transmission has included a similar request in its EB-2010-0002 application.

h) Is there any new or additional information since the June 30, 2010 filing of this application that would assist the Board in assessing this request?

Response:

Consistent with Hydro One Brampton's response to Board Staff IR # 54 (part h), this account would not be used in 2011 if IFRS implementation is deferred to 2012.

Ontario Energy Board Interrogatory # 56

Ref: Exhibit 9/ Tab 1/ Schedule 1.0/ Page 1-7 – Account 1562 and 1592

Hydro One Brampton is requesting to dispose its PILs accounts 1562 and 1592.

The March 3, 2008 letter of the Board relating to the combined PILs proceeding (EB-2008-0381) stated the following:

"Going forward, it is the Board's expectation that the decision stemming from the combined proceeding will be used to determine the final account balances with respect to account 1562, Deferred PILs for the remaining distributors. The Board intends to proceed with the review and disposition of the account 1562, Deferred PILs balances for the remaining distributors subsequent to the completion of the combined proceeding."

Why is Hydro One Brampton requesting to dispose of the balances in accounts 1562 and 1592, given that the PILs proceeding to determine the methodology to be used for calculation and disposition of the PILs account balances has not yet concluded?

Preamble to remaining interrogatories on Hydro One Brampton's request for disposition of Accounts 1562 and 1592:

If Hydro One Brampton wishes to continue with the review and disposition of accounts 1562 and 1592 as part of the instant proceeding, responses to the following interrogatories will be required in order to assess the quantum of the accounts and compliance with the Board's established methodology. The interrogatories are numerous as the quantum in account 1562 is the result of accounting entries and calculations dating back to 2001. The interrogatories examine Hydro One Brampton's entries in its PILs proxy model for each year from 2001 to 2005 as well as reconciling those entries with Hydro One Brampton's tax filings and rate applications for each of the subject years.

Response:

Hydro One Brampton is participating in the PILs proceeding only as an intervenor. While a number of the issues identified during the proceeding are common to many LDC's, the fact is that only the three applicants have filed evidence in the proceeding, as is normally the case; and it has become clear in the proceeding that issues will be addressed only insofar as they affect one or more of the three applicants. Hydro One Brampton has submitted evidence in its rate submission that is not common to other LDC's or that has not been provided as evidence by the three named utilities that Hydro One Brampton believes that the submitted evidence is relevant to support its circumstances and position. That evidence cannot and will not be addressed in the PILs proceeding.

Ontario Energy Board Interrogatory # 57

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Corporate Tax Returns- Federal T2 and Ontario CT23

a) Please provide copies of the signed original and amended federal T2 tax returns (T2 jacket and supporting schedules) and the Ontario CT23 tax returns for the 2001 through 2006 tax years that were filed with the tax authorities. Please do not file any forms containing confidential information such as employee names and social insurance numbers.

Response:

See **Appendix Q**

b) Please provide the financial statements that were attached to the tax returns.

Response:

See **Appendix Q**

c) Please provide all of the Notices of Assessment, Reassessment and Statements of Adjustments for the tax years 2001 through 2009.

Response:

See **Appendix R**

Ontario Energy Board Interrogatory # 58

Ref: Exhibit 9 / Tab 1/ Schedule 5.0/ Page 4 / Table 1 – PILs 1562 True-up Summary 2001 to 2006

a) Please provide the Board decisions and Orders, rate application models, and PILs proxy models for 2002 through 2005 that support the PILs rate proxy entitlement shown in this summary continuity schedule.

Response:

Please see **Appendix S** for the requested information

b) Please provide the live Excel worksheets that show how Hydro One Brampton calculated the PILs proxy entitlement for each year shown in the summary continuity schedule.

Response:

Hydro One Brampton has included the updated live Excel worksheets showing PILs proxy entitlement calculations for 2001 through 2005. These have been updated reflect OEB's instructions. Please refer to **Appendix T**.

c) Please provide the live Excel worksheets that Hydro One Brampton used to calculate the amounts billed to customers for the years 2002 through 2006.

Response:

Hydro One Brampton has included the updated live Excel worksheets showing PILs amounts billed to customers for the years 2001 through 2005. These have been updated to reflect the OEB's instructions. Please refer to **Appendix T.**

d) Please explain why no PILs proxy amount appears in the 2001 column.

Response:

The revised 2001 PILs models have included the PILs proxy amount for 2001. Please see **Appendix V**, file "HOBNI SIMPILs 2001 Aug to Dec With Interest Claw-back" and **Appendix W** file "HOBNI SIMPILs 2001 Aug to Dec Without Interest Claw-back" for detail.

e) The RRR SIMPIL filings were made in the summer following the applicable tax years 2001-2005 after the tax returns had been prepared and filed with the tax authorities. Please explain why Hydro One Brampton has shown the true-up and deferral account variances in the applicable tax year rather than in the following year.

Response:

Hydro One Brampton has adjusted PILs models, and the true-up and deferral account variances are now shown in the following year instead of the applicable tax year.

f) Please explain why Hydro One Brampton has not shown interest carrying charges on the summary continuity schedule.

Response:

Hydro One Brampton has adjusted the PILs models and interest carrying charges are now shown on the revised summary continuity schedule.

g) Hydro One Brampton has referred to an interest amount to be collected related to the balance in 1562 [Ref: Exhibit 9/ Tab 1/ Schedule 1/ Pages 4 and 5]. How was the interest recalculated after Hydro One Brampton amended its treatment of the interest claw-back? That is,

by month, average annual or some other method.

Response:

Interest was calculated monthly

h) Hydro One Brampton has stated on Exhibit 9/ Tab 1/ Schedule 1/ Page 1 that it used 0.55% for the period January 1 to December 31, 2010.

I. What rates of interest did Hydro One Brampton use to accrue interest from April 1, 2006 to December 31, 2009?

Response:

Hydro One Brampton applied the following rates to interest calculation for the period April 1, 2006, to December 31, 2009:

	2006				2007				2008				2009			
	QTR 1	QTR 2	QTR 3	QTR 4	QTR 1	QTR 2	QTR 3	QTR 4	QTR 1	QTR 2	QTR 3	QTR 4	QTR 1	QTR 2	QTR 3	QTR 4
Yearly rate		4.140%	4.590%	4.590%	4.590%	4.590%	4.590%	5.140%	5.140%	4.080%	3.350%	3.350%	2.450%	1.000%	0.550%	0.550%
Monthly Equivalent Rate		0.345%	0.383%	0.383%	0.383%	0.383%	0.383%	0.428%	0.428%	0.340%	0.279%	0.279%	0.204%	0.083%	0.046%	0.046%

II. What rate of interest did Hydro One Brampton use to calculate interest for the period August 1, 2001 to April 30, 2006?

Response:

Hydro One Brampton applied a yearly rate of 7.00% to interest calculation for the period August 1, 2001 to March 31, 2006. This approximated to 0.583% per month. For the period April 1, 2006, to April 30, 2006, a yearly interest rate of 4.14% was applied. This totaled 0.345% per month.

i) Large Corporation Tax (LCT) was repealed with effect from January 1, 2006. Has Hydro One Brampton included the proportional amount of LCT for the period January 1 to April 30, 2006 in its summary continuity schedule? If not, please explain.

Response:

Yes, Hydro One Brampton has included the proportional amount of the Federal Large Corporation Tax (LCT) for the period January 1, 2006 to April 30, 2006 in the revised summary continuity schedule

j) Did Hydro One Brampton use the final tax items in the original, amended, assessed or reassessed tax returns for purposes of calculating the SIMPIL/ PILs true-up amounts for 2001 to 2005?

Response:

Yes. However, there were immaterial adjustments totaling $22,220 that were not included in the calculations.

Ontario Energy Board Interrogatory # 59

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Stand-alone Principle

a) How has Hydro One Brampton applied the stand-alone principle in its evidence? That is, were the Large Corporation Tax and Ontario Capital Tax thresholds/ exemptions pro-rated among regulated and non-regulated companies in the corporate group or were they allocated 100% for regulatory purposes?

Response:

Hydro One Brampton is a subsidiary of Hydro One Inc., and therefore both Large Corporation Tax (LCT) and Ontario Capital Tax (OCT) thresholds/exemptions were prorated.

b) Was this treatment specifically approved by the Board in its decisions on Hydro One Brampton's applications for 2002 and subsequent years?

Response:

Yes

Ontario Energy Board Interrogatory # 60

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Accounts Used

a) In Hydro One Brampton's opinion, does the balance in account 1562 establish the obligation to, or the receivable from, the distributor's ratepayers?

Response:

Yes. Please see **Appendix U**.

c) If Hydro One Brampton used the 1563 contra account, how should its balance be cleared in conjunction with the disposition of the 1562 control account? If Hydro One Brampton did not use account 1563, does it have an opinion on the disposition methodology of 1563?

Response:

Hydro One Brampton used the 1563 contra account believes that its balance should be drawn down to income by the same amount that account 1562 is drawn down by rider billed/credited to customers. Account 1563 would be drawn down to zero, while account 1562 would continue to be drawn down based on amounts billed/credited to customers through the rider, until the rider ceases. The remaining balance in account 1562 would be disposed of at a future rate proceeding, as part of Group 1 accounts as a further prudency review would not be required.

Ontario Energy Board Interrogatory # 61

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Compliance with APH and Related FAQs

a) Has Hydro One Brampton correctly applied the true-up variance concepts established by the Board's guidance?

Response:

Yes

b) How did Hydro One Brampton calculate or determine the PILs tax amounts billed to customers for the period 2001 - 2006?

Response:

The amounts shown in the revised submissions were calculated based on guidelines presented by the OEB in the "PILs 1562 Calculation" tab in the SIMPILs Excel worksheets.

The amount billed to customers between March 1, 2002, and March 31, 2004, was based on actual monthly volumes/load by class for the period (including net unbilled at period end), multiplied by the PILs volumetric proxy rates by class (from the 2001 and 2002 RAM decision); plus, monthly customer counts by class in the same period multiplied by the PILs fixed charge rate components in the 2001 and 2002 RAM decision.

From April 1, 2004, to December 31, 2004, the amount billed to customers was based on the sum product of the 2004 RAM approved volumetric rates by class and the actual monthly volumes/load by class for the period.

For the period January 1, 2005, to March 31, 2005, the amount billed to customers was calculated as the sum product of the 2004 RAM approved volumetric rates by class and the actual monthly volumes/load by class for the period (January 1, 2005 to March 31, 2005).

From April 1, 2005, to December 31, 2005, the amount billed to customers was based on the sum product of the 2005 RAM approved volumetric rates by class and the actual monthly volumes/load by class for the period.

For the period January 1, 2006, to April 30, 2006, the amount billed to customers equals the sum product of the 2005 RAM approved volumetric rates by class and the actual monthly volumes/load by class for the period (January 1, 2006, to April 30, 2006)

c) How did Hydro One Brampton treat unbilled revenue in the amounts recorded in 1562 relating to billings to customers? If information was not available to calculate unbilled revenue as at April 30, 2006 please identify where in its evidence for this proceeding has Hydro One Brampton provided this information?

Response:

Hydro One Brampton submits revised amounts recorded in account 1562 relating to billings to customers. Hydro One Brampton did not use unbilled revenue amounts to record the billings to customers, but rather used actual prorated billing quantities from the Customer Information System for each respective rate year. In addition, the rate slivers for variable and fixed distribution rates (as applicable) relating to PILS for each rate year were applied to the prorated consumption data and used to determine billing amounts to customers. Only the consumption data for billings in March 2002 related to post-March 1, 2002, consumption were included at the start of the period, and all consumption data for pre May 1, 2006, but billed subsequent to this date was used in the billings to customers calculations**.**

d) Does Hydro One Brampton's liability for post-employment benefits relate only to people directly employed by Hydro One Brampton?

Response:

Yes.

e) Did Hydro One Brampton use a materiality threshold to determine true-up items in the models? If yes, how did Brampton determine the materiality threshold that it used for each year 2001-2005?

Response:

No. Materiality was zero.

Ontario Energy Board Interrogatory # 62

Ref: Exhibit 9 / Tab 1/ Schedule 5.0/ Page 4 / Table 1 – Treatment of Short Tax Years or Stub Periods

2001 PILs Proxy (also termed 2001 Deferral Account Allowance)

a) In Table 1, how did Hydro One Brampton recognize and record the continued collection of the 2001 PILs proxy amount in rates from 2002 through the removal of the 2001 proxy from rates in 2004?

Response:

Hydro One Brampton included in the proxy in the "board approved PILs tax proxy from decisions" line, and the amounts billed to customers was recorded in the "PILs billed to (collected from) customers" line on Table 1.

b) How many times has Hydro One Brampton recorded true-up items related to the 2001 PILs amount included in 2002 rates in account 1562? Has Hydro One Brampton provided evidence supporting this treatment? If yes, please identify where the evidence can be found.

Response:

Hydro One Brampton continued to capture the difference between billed and proxy PILs amounts from 2002 to 2004.

c) Should the 2001 PILs amount be trued up to specified items from tax filings and recorded in the period after the 2002 rate year until the 2001 deferral account allowance was removed from rates in 2004?

Response:

No.

January 1 to April 30, 2006

d) For the period January 1 to April 30, 2006 what variances did Hydro One Brampton consider for true-up? Please explain.

Response:

None. Hydro One Brampton did not prepare a SIMPILs true-up calculation for the period January 1, 2006, to April 30, 2006.

Ontario Energy Board Interrogatory # 63

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Tax Impacts of Movements in Regulatory Asset and Liability Balances

a) How did Hydro One Brampton deal with tax impacts of regulatory asset and liability movements, and collections of same, from the 2001 to 2005 tax years in the SIMPIL/ PILs true-up model reconciliations? Regulatory assets and liabilities refer to the established range of accounts plus the new 1590 and 1595 accounts.

Response:

Hydro One Brampton excluded regulatory assets/liability movements from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment used for those amounts. Hydro One Brampton accounted for these as items that are not trued up in the TaxRec3 tab of the SIMPIL models for each year from 2001 to 2005.

b) Did Hydro One Brampton follow the guidance in the 2004 and 2005 RRR SIMPIL filing guidelines concerning regulatory asset movements being excluded in the determination of true-up amounts?

Response:

Yes, the Company believes it has followed the guidelines.

c) Did Hydro One Brampton follow the guidance provided in Chapter 7, page 61, of the Report of the Board on 2006 EDR Handbook regarding movements in regulatory assets?

Response:

Yes, the Company believes it has followed the guidelines.

d) Since Hydro One Brampton has collected the regulatory asset amounts (other than 1562 and 1592), and has received the benefit of declining income tax rates during the period 2001 to 2009, should the movement in these deferral and variance accounts be used to determine additional true-up amounts from ratepayers in the SIMPIL/ PILs calculations? Please explain.

Response:

No. The true up amount up to 2006 captured these benefits of declining tax rates and then subsequent to that changes that resulted from tax rates were tracked in a variance account

Ontario Energy Board Interrogatory # 64

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Tax Rates Used for True-up Calculations

For each year 2001 through 2005, please describe how Hydro One Brampton calculated and selected the income tax rate that it used to calculate the true-up amounts which were included in the reconciliation of the Account 1562 balance.

Response:

Income tax rates for 2001 through 2005 were calculated based on information in the tax returns for these years, that is, net income tax payable divided by net taxable income. The maximum income tax rate used to calculate true-up amounts is the difference between the legislated income tax rate and the federal surtax rate.

Ontario Energy Board Interrogatory # 65

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Interest Claw-back

a) Did Hydro One Brampton use the maximum amount of deemed interest from its 2002 and subsequent applications as the threshold to determine the excess interest claw-back?

Response:

Yes. Hydro One Brampton used the maximum amount of deemed interest as established in the SIMPILs models. Please see **Appendices V and W.**

b) Does Hydro One Brampton agree that the interest claw-back has been a feature of the Board's PILs/ SIMPIL methodology since 2001-2002?

Response:

The claw-back feature has been a part of the SIMPIL model methodology, but Hydro One Brampton submits that there have been unintended results and has explained the Company's position on this in the original filing.

c) Was the actual debt outstanding for the period 2001 through 2005 borrowed from third parties, Hydro One Inc., or other associated or affiliated companies?

Response:

Hydro One Inc.

d) Please provide an analysis of the amounts borrowed and applicable interest rates for each type of debt instrument with each of third parties, Hydro One Inc. and associated/ affiliated companies for the period 2001-2005.

Response:

HOBNI has had one debt instrument outstanding with Hydro One Inc. throughout the period in question. This instrument is a 30 year promissory note the principal amount of which is $143.0 M and bears interest at 6.95%. HOBNI did not have any other debt instruments during the same period

e) Please complete the attached Excel worksheet for the analysis of Hydro One Brampton's actual balance sheets from 1999 through 2009.

Response:

Please see **Appendix AY**

Ontario Energy Board Interrogatory # 66

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – 2001 PILs Models

Evidence Indentified as PILs Files 2001-2005. These are the Excel models that generated the true-up entries for account 1562. The following questions are related to the Excel model named "Hydro One Brampton PILs-2001_EB-2008-0381_20100429 CEC & RA Adj.xlsm".

a) TAXCALC initial estimate column C does not agree with the models submitted in the 2002 RAM application. The tax rates and other numbers are different. Please correct to agree with the 2001-2002 application evidence and resubmit the evidence.

Response:

Hydro One Brampton has re-run and updated the 2001 SIMPIL model. TAXCALC initial estimate column C was updated to agree with the models submitted in the 2002 RAM application. The tax rates and other numbers have also been updated to agree with the 2001-2002 application evidence. Please see **Appendix V,** file "HOBNI SIMPILs 2001 Aug to Dec With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2001 Aug to Dec Without Interest Claw-back" for detail.

b) TAXREC

I. Cell C109: Capitalized interest is interest and should be added to interest expense for purposes of the claw-back calculations.

Response:

Capitalized interest and interest expense are added in the 2001 SIMPIL model for the purpose of the interest claw-back calculation. Please refer to cell E201 (TAXCALC tab) in **Appendix V** file "HOBNI SIMPILs 2001 Aug to Dec With Interest Claw-back" for detail.

II. The Ontario tax rate of 13.10% shown in cell C150 is higher than the maximum statutory rate of 12.5% for the fourth quarter 2001. Please explain why and show the calculations.

Response:

Hydro One Brampton commenced PILs calculation/assessment on August 1, 2001. During the period January 1, 2001, to September 30, 2001, the Ontario corporate income tax rate was 14.00%. This rate was subsequently reduced to 12.50%, effective October 1, 2001. As a result of the tax rate differences, Hydro One Brampton's tax rate for 2001 was higher than the 12.50% maximum statutory rate for the fourth quarter. Please refer to table immediately below.

Income Tax Payable - Per Tax Filings 2001				
Income (Loss) For Income Tax Purposes				
		Federal		**Ontario**
Net Income Per Financial Statements		3,872,829		3,872,829
Additions:				
Provision for Income Taxes - Current			-	
Amortization of tangible assets	4,761,108		4,761,108	
Non-Deductible meals and entertainment expenses	12,440		12,440	
Reserves from Financial Statements - Balance at the end of the year	3,900,000		3,900,000	
Software expensed per F/S	33,549		33,549	
Amortization of debt discount			-	
Partnership income per T5013 (net of 2001 loss)			-	
Total Additions		8,707,097		8,707,097
Deductions:				
Gain on disposal of assets per financial statements	89,386		89,386	
Capital Cost Allowance from Schedule 8	3,497,596		3,497,596	
Cumulative eligible capital deduction from Schedule 10	1,287,711		1,296,183	
Reserves from Financial Statements - Balance at the beginning of the year	3,780,000		3,780,000	
OPEB amounts capitalized			-	
Capitalized interest	229,306		229,306	
Prospectus & underwriting fees	64,807		64,807	
Capital tax not expensed	325,887		325,887	
Other deductions - Income not earned on movement of Regulatory A/C's	655,622		655,622	
Total Deductions		9,930,315		9,938,787
Taxable Income		2,649,611		2,641,139
Base Federal Income Tax @38%		1,006,852		
Provincial Income Tax @14% - 61 days of 153 days				147,420
Provincial Income Tax @12.5% - 92 days of 153 days				198,517
Total Provincial Income Tax				345,937
Provincial tax/Taxable income				13.10%
Number of days in year				365
Number of days in taxation year				153
Days in taxation year between August 1, 2001 & September 30, 2001				61
Days in taxation year after Septemeber 30, 2001				92
Ontario taxation rate - Janaury 1, 2001 to September 30, 2001				14.00%
Ontario taxation rate - October 1, 2001 to December 31, 2001				12.50%

c) TAXREC2 – Row 98 – Combined amount of $390,694.

I. Do prospectus and underwriting fees relate to debt issued, and what is the amount?

Response:

Prospectus and underwriting fees relate to the debt issued. On issuance of this promissory note, $773 thousand of transaction costs relating to Hydro One Brampton incurred by Hydro One were transferred to the Company. For tax purposes, financing expenses are deducted at 20% per year.

The amount of prospectus and underwriting fees for 2001 is $64,807.

II. Did Hydro One Brampton disclose these fees for GAAP purposes as financing charges in its financial statements?

Response:

The 2001 financial statements of Hydro One Brampton were unaudited, but were disclosed on the consolidated financial statements of Hydro One Inc.

III. Should Hydro One Brampton consider financing charges as interest for purposes of the interest claw-back calculations?

Response:

No. In the revised SIMPILs models, Hydro One Brampton transferred amortization of debt discount from TAXREC 2 to TAXREC 3. No true-up is applied to items in TAXREC 3. Please see **Appendices U and V** for detail

IV. How much is the capital tax expense in the combined amount?

Response:

The capital tax expense amount was $325,887.

V. It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response:

Hydro One Brampton has adjusted the 2001 SIMPIL model and capital taxes are now recorded in TAXREC 3 where no true-up is applied. Please refer to the revised models in **Appendix V,** file "HOBNI SIMPILs 2001 Aug to Dec With Interest Claw-back" and **Appendix W,** file "HOBNI SIMPILs 2001 Aug to Dec Without Interest Claw-back" for detail.

d) Tax Rate Tables: Upon refilling, please ensure that the correct income tax rates are used.

Response:

Hydro One Brampton has updated the tax rates tables. Please see models in **Appendix V**, file "HOBNI SIMPILs 2001 Aug to Dec With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2001 Aug to Dec Without Interest Claw-back" for more information.

Ontario Energy Board Interrogatory # 67

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – 2002 PILs Models

Evidence Indentified as PILs Files 2001-2005. These are the Excel models that generated the true-up entries for account 1562. The following questions are related to the Excel model named "Hydro One Brampton PILs-2002_EB-2008-0381_20100324 CEC & RA Adj.xlsm".

a) Tax and Accounting Reserves

I. Are the regulatory reserves of $144,843 shown in cell C60 related to regulatory assets?

Response:

No. They are allowance for doubtful accounts. Please see the updated models in **Appendix V**, file "HOBNI SIMPILs 2002 With Interest Claw-back" and **Appendix W** file "HOBNI SIMPILs 2002 Without Interest Claw-back" for more detail.

II. Should movements in regulatory assets true-up to the ratepayers? Please explain.

Response:

Movements in regulatory assets should not true-up to the ratepayers. Regulatory assets should be excluded from PILs calculations both when they are created, and when they are collected, regardless of the actual tax treatment accorded those amounts. The change in Regulatory Assets/Liabilities are not part of the determination of accounting income and since accounting income is used in the determination of taxable income these should have no bearing on "Regulatory Income Taxes". Movement of Regulatory Assets from 2001 to 2006 was unpredictable and fluctuated during this time period. Over the long run, the movement of regulatory assets will cancel each other out. However, the impacts to taxes will not necessarily cancel each other out.

b) TAXREC2 – Row 98 – Combined amount of $155,404.

I. Do prospectus and underwriting fees relate to debt issued, and what is the amount?

Response:

See response in Exhibit 12 Tab 1 Schedule 66 (c)(I)

The amount of prospectus and underwriting fees for 2002 is $154,670.

II. Did Hydro One Brampton disclose these fees for GAAP purposes as financing charges in its financial statements?

Response:

The fees of $773 thousand were disclosed for GAAP purposes in Note 8 of the 2002 financial statements.

III. Should Hydro One Brampton consider financing charges as interest for purposes of the interest claw-back calculations?

Response:

See response in Exhibit 12 Tab 1 Schedule 66 (c)(III)

IV. How much is the capital tax expense in the combined amount?

Response:

The capital tax expense amount was $734.

V. It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response:

Hydro One Brampton has adjusted the 2002 SIMPIL model and capital taxes have been recorded in TAXREC 3 where no true-up is applied. Please see the updated models in **Appendix V**, file "HOBNI SIMPILs 2002 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2002 Without Interest Claw-back" for more detail.

Ontario Energy Board Interrogatory # 68

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – 2003 PILs Models

Evidence Indentified as PILs Files 2001-2005. These are the Excel models that generated the true-up entries for account 1562. The following questions are related to the Excel model named "Hydro One Brampton PILs-2003_EB-2008-0381_20100429 CEC & RA Adj.xlsm".

a) Tax and Accounting Reserves

I. Are the regulatory reserves of $144,843 shown in cell C48 and $353,625 in cell C61 related to regulatory assets?

Response:

No. They are allowance for doubtful accounts. The $144,843 represents opening balance while the $353,625 is closing balance.

II. Should movements in regulatory assets true-up to the ratepayers? Please explain.

Response:

See response in Exhibit 12 Tab 1 Schedule 67 (a)(II).

b) TAXREC2 – Row 98 – Combined amount of $194,605.

I. Do prospectus and underwriting fees relate to debt issued, and what is the amount?

Response:

See response in Exhibit 12 Tab 1 Schedule 66 (c)(I).

The amount of prospectus and underwriting fees for 2003 is $154,606

II. Did Hydro One Brampton disclose these fees for GAAP purposes as financing charges in its financial statements?

Response:

The fees of $773 thousand were disclosed for GAAP purposes in Note 8 of the 2003 financial statements

III. Should Hydro One Brampton consider financing charges as interest for purposes of the interest claw-back calculations?

Response:

See response in Exhibit 12 Tab 1 Schedule 66 (c)(III).

IV. How much is the capital tax expense in the combined amount?

Response:

The capital tax expense amount was $39,999.

V. It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response:

Hydro One Brampton has adjusted the 2003 SIMPIL model and capital taxes have been recorded in TAXREC 3 where no true-up is applied. Please see the updated models in **Appendix V**, file

"HOBNI SIMPILs 2003 With Interest Claw-back" and **Appendix W,** file "HOBNI SIMPILs 2003 Without Interest Claw-back" for more information.

Ontario Energy Board Interrogatory # 69

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – 2004 PILs Models

Evidence Indentified as PILs Files 2001-2005. These are the Excel models that generated the true-up entries for account 1562. The following questions are related to the Excel model named "Hydro One Brampton PILs-2004_EB-2008-0381_20100429 CEC & RA Adj.xlsm".

a) Tax and Accounting Reserves

I. Are the regulatory reserves of $353,625 shown in cell C48 and $3,485,134 in cell C61 related to regulatory assets?

Response:

No. The $353,625 was opening balance for allowance for doubtful accounts. The amount of $3,485,134 was made up of the following closing balances:

Legal Claim	$268,942
Allowance for doubtful accounts	$335,000
Bill 4 Deferred revenue	$2,881,192
Total	$3,485,134

II. Please provide a table that compares the reserves on the audited balance sheet with the reserve amount of $3,485,134. Please explain.

Response:

Audited Balance Sheet Item	Audited Balance Sheet 2004 ('000)	2004 Tax Return ('000)
Accounts receivable (includes allowance for doubtful accounts)	48,338	 335
Regulatory Assets (includes Bill 4 deferred revenue)	9,827	 2,881
Long term accounts payable and accrued liabilities (includes legal claim)	262	 269

Should movements in regulatory assets true-up to the ratepayers? Please explain.

Response:

See response in Exhibit 12 Tab 1 Schedule 67 (a)(II).

b) TAXREC2

I. Other additions in cell C41 in the amount of $198,431. What items does this amount represent? Should they true-up under the methodology? Please explain.

Response:

They should not true-up. This amount consists of:

Partnership income	$5,479.00

Reversal of O/H deduction claim in prior year	$192,862.00

In the revised models both items have been included in TAXREC 3 where true-up is not applied. Please see **Appendix V**, file "HOBNI SIMPILs 2004 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2004 Without Interest Claw-back" for more information.

II. Capital tax addition in C42 in the amount of $44,351. It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response:

Hydro One Brampton has adjusted the SIMPILs 2004 model and capital taxes have been recorded in TAXREC 3 where no true-up is applied. Please see **Appendix V**, file "HOBNI SIMPILs 2004 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2004 Without Interest Claw-back" for more information.

III. Depreciation expense cell C43 in the amount of $172,973 should not true up under the methodology and should be included with the amount shown in TAXREC cells C43 and C61. Please explain why Hydro One Brampton believes the amount should true up to ratepayers.

Response:

Including this amount in cells C43 and C61 of TAXREC would affect taxable income in that it would not reflect the amount reported on the tax return. In the revised model, Hydro One Brampton has included the amount in TAXREC 3 where true-up is not applied. Please see **Appendix V**, file "HOBNI SIMPILs 2004 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2004 Without Interest Claw-back" for more information.

IV. Row 100 RSVA in the amount of $39,748. Should regulatory asset movements be trued up to ratepayers? Please explain.

Response:

No. This amount is now included in TAXREC 3 where no true-up is applied. Please refer to the updated models in **Appendix V**, file "HOBNI SIMPILs 2004 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2004 Without Interest Claw-back" for more information.

V. Row 101 – Combined amount of $154,606.

i) Do prospectus and underwriting fees relate to debt issued? If yes, please identify the amount.

Response:

See response in Exhibit 12 Tab 1 Schedule 66 (c)(I).

The amount of prospectus and underwriting fees for 2004 is $154,606.

ii) Did Hydro One Brampton disclose these fees for GAAP purposes as financing charges in its financial statements?

Response:

The fees of $773 thousand were disclosed for GAAP purposes in Note 9 of the 2004 financial statements.

iii) Should Hydro One Brampton consider financing charges as interest for purposes of the

interest claw-back calculations?

Response:

See response in Exhibit 12 Tab 1 Schedule 66 (c)(III).

iv) How much is the capital tax expense in the combined amount?

Response:

The amount was $0.00.

v) It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response:

Hydro One Brampton has adjusted the 2004 SIMPIL model and capital taxes have been recorded in TAXREC 3 where no true-up is applied. Please see **Appendix V**, file "HOBNI SIMPILs 2004 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2004 Without Interest Claw-back" for more information.

Ontario Energy Board Interrogatory # 70

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – 2005 PILs Models

Evidence Indentified as PILs Files 2001-2005. These are the Excel models that generated the true-up entries for account 1562. The following questions are related to the Excel model named "Hydro One Brampton PILs-2005_EB-2008-0381_20100324 CEC & RA Adj.xlsm".

a) TAXCALC initial estimate column C does not agree with the models submitted in the 2005 RAM application. The tax rates and other numbers are different. Please correct to agree with the 2005 application evidence and resubmit the evidence.

Response:

Hydro One Brampton has updated the TAXCALC initial estimate column C to agree with the models submitted in the 2005 RAM application. The tax rates and other numbers have also been updated to agree with the 2005 application evidence. Please see **Appendix V**, file "HOBNI SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

b) Tax and Accounting Reserves

I. Are the regulatory reserves of $3,485,134 shown in cell C48 and $7,221,831 in cell C61 related to regulatory assets?

Response:

No. Please refer to Question 69(a)(I) above for the items included in $3,485,134. The amount for $7,221,831 was made up of the following closing balances:

Legal Claim	$249,401
Allowance for doubtful accounts	$370,864
Bill 4 Deferred revenue	$6,601,566
Total	$7,221,831

II. Please provide a table that compares the reserves on the audited balance sheet with the reserve amount of $7,221,831. Please explain.

Response:

Audited Balance Sheet Item	Audited Balance Sheet 2005 ('000)	2005 Tax Return ('000)
Accounts receivable (includes allowance for doubtful accounts)	48,768	 371
Regulatory assets (includes Bill 4 deferred revenue	8,780	 (6,602)
Long term accounts payable and accrued liabilities (Includes legal claim)	249	 249

III. Should movements in regulatory assets true-up to the ratepayers? Please explain.

Response:

See response in Exhibit 12 Tab 1 Schedule 67 (a)(II)..

c) TAXREC2

I. Capital tax addition in C42 in the amount of $795,058. It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response:

Hydro One Brampton has made adjustments to the 2005 SIMPILs model and capital taxes are now recorded in TAXREC 3 where no true-up is applied. Please see **Appendix V**, file "HOBNI SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

II. Depreciation expense cell C43 in the amount of $236,715 should not true up under the methodology and should be included with the amount shown in TAXREC cells C43 and C61. Please explain why Hydro One Brampton believes the amount should true up to ratepayers.

Response:

Including this amount in cells C43 and C61 of TAXREC would affect taxable income in that it would not reflect the amount reported on the tax return. In the revised model, Hydro One Brampton has included the amount in TAXREC 3 where no true-up is applied. Please see **Appendix V,** file "HOBNI SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

III. Row 98 capital tax in the amount of $829,705. Capital tax also appears in row 101 as part of the combined amount of $154,606. Please explain why. It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response;

Hydro One Brampton has made adjustments to the 2005 SIMPILs model and capital taxes are now recorded in TAXREC 3 where no true-up is applied. Please see **Appendix V**, file "HOBNI

SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

IV. Row 99 Other deductions in the amount of $130,279.What items does this amount represent? Should they true-up under the methodology? Please explain.

Response:

This amount consists of:

OPEB costs capitalized included in Schedule 13	$87,900.00
Removal cost for West Drive	$42,379.00
Total	$130,279

Capitalized OPEB cost is considered a true-up item and has been included in TAXREC 2 in the revised models. However, no true-up was applied to removal costs – they were included in TAXREC 3. Please see **Appendix V**, file "HOBNI SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

V. Row 100 RSVA in the amount of $1,183,521. Should regulatory asset movements be trued up to ratepayers? Please explain.

Response:

No. This amount is now included in TAXREC 3 where no true-up is applied. Please refer to the updated models in **Appendix V**, file "HOBNI SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

VI. Row 101 – Combined amount of $154,606.

i) Do prospectus and underwriting fees relate to debt issued? If yes, please identify the amount.

Response:

Prospectus and underwriting fees relate to the debt issued. On issuance of this promissory note, $773 thousand of transaction costs incurred by Hydro One Inc. were transferred to the Company. For tax purposes, ITA section 20(e) allows the deduction of financing expenses to be deducted at 20% per year.

The amount of prospectus and underwriting fees for 2005 is $154,606.

ii) Did Hydro One Brampton disclose these fees for GAAP purposes as financing charges in its financial statements?

Response:

2005 financial statements.

iii) Should Hydro One Brampton consider financing charges as interest for purposes of the interest claw-back calculations?

Response:

See response in Exhibit 12 Tab 1 Schedule 66 (c)(III).

iv) How much is the capital tax expense in the combined amount?

Response:

The amount was $0.00.

v) It is staff's understanding that capital tax should not true-up to ratepayers for income tax purposes under the methodology since capital taxes are expense and part of net income. Why does Hydro One Brampton believe that capital taxes should true up for income tax purposes?

Response:

Hydro One Brampton has made adjustments to the 2005 SIMPILs model and capital taxes are now recorded in TAXREC 3 where no true-up is applied. Please see **Appendix V**, file "HOBNI SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

VII. The Materiality Level has been set to zero. The model has segregated and classified the amounts listed as deductions into material and non-material categories. Non-material deductions do not true up if materiality is set to more than zero. Please explain why the model has not trued up all of the deductions.

Response:

Hydro One Brampton has updated the SIMPILs models and all of the deductions are now being trued-up

d) Tax Rate Tables: Upon refilling, please ensure that the correct income tax rates are used.

Response:

Hydro One Brampton has updated the tax rates tables. Please see **Appendix V**, file "HOBNI SIMPILs 2005 With Interest Claw-back" and **Appendix W**, file "HOBNI SIMPILs 2005 Without Interest Claw-back" for more information.

Ontario Energy Board Interrogatory # 71

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – PILs model update

After correcting the models for the years 2001 through 2005, please make copies and rename the models to indicate that one set shows the interest claw-back and the other set of models does not.

a) In the set labeled "Without interest claw-back" please insert zero (0) in the appropriate cell in TAXCALC section V) Interest Portion of True-up. This is cell E206 in the models for 2002-2005. Please ensure that zero now appears in cell E112 after adjusting cell E206.

Response:

Hydro One Brampton has inserted zero in the appropriate cell in TAXCALC section V) Interest Portion of True-up. Please see **Appendices V and W** for detail.

b) Please provide a revised summary table similar to Exhibit 9/ Tab 1/ Schedule 5.0/ Page 4/ Table 1 for the set of models labeled "With interest claw-back" and another summary for the set "Without interest claw-back". It might be easier not to recalculate carrying charges for this comparison.

Response:

Hydro One Brampton has included two revised PILs summary continuity schedule below. The first one shows the results of the models "with interest claw-back" and the other shows results "without interest claw-back."

PILs 1592 True-up Summary Continuity Schedule (with Interest Claw-back) 2001 to 2006

EB-2010-0132								
Summary PILs 1562 Balance - With Interest Claw-back								
Utility Name: Hydro One Brampton								
Reporting period: 2001- 2005			**Sign Convention: + for increase; - for decrease**					
Year start:		10/1/2001	1/1/2002	1/1/2003	1/1/2004	1/1/2005	1/1/2006	
Year end:		12/31/2001	12/31/2002	12/31/2003	12/31/2004	12/31/2005	4/30/2006	Total
Opening balance:	=	0	3,779,196	2,922,687	2,541,125	1,186,466	438,874	0
Board-approved PILs tax proxy from Decisions (1)	+/-	3,735,614	7,536,775	11,272,389	8,470,679	1,884,194	2,457,305	**35,356,957**
PILs proxy from April 1, 2005 - input 9/12 of amount	+					5,528,937		5,528,937
True-up Variance Adjustment Q4, 2001 (2)	+/-		2,951	0				2,951
True-up Variance Adjustment (3)	+/-		0	-800,056	-846,448	727,081	1,321,291	401,868
Deferral Account Variance Adjustment Q4, 2001 (4)	+/-				0			0
Deferral Account Variance Adjustment (5)	+/-		0	0	-404,274	-481,842	0	-886,116
Adjustments to reported prior years' variances (6)	+/-							0
LCT repeal	+/-						-126,198	-126,198
Carrying charges (7)	+/-	43,582	284,693	166,096	76,669	15,410	-2,096	584,355
PILs billed to (collected from) customers (8)	-	**0**	**-8,680,929**	**-11,019,991**	**-8,651,285**	**-8,421,372**	**-2,906,720**	**-39,680,297**
Ending balance: # 1562		3,779,196	2,922,687	2,541,125	1,186,466	438,874	1,182,457	1,182,457

PILs 1592 True-up Summary Continuity Schedule (without Interest Claw-back) 2001 to 2006 [USE SMALLER FONT]

EB-2010-0132								
Summary PILs 1562 Balance - Without Interest Claw-back								
Utility Name: Hydro One Brampton								
Reporting period: 2001- 2005			Sign Convention: + for increase; - for decrease					
Year start:		10/1/2001	1/1/2002	1/1/2003	1/1/2004	1/1/2005	1/1/2006	
Year end:		12/31/2001	12/31/2002	12/31/2003	12/31/2004	12/31/2005	4/30/2006	Total
Opening balance:	=	0	3,779,196	2,922,687	3,592,329	3,157,459	3,513,616	0
Board-approved PILs tax proxy from Decisions (1)	+/-	3,735,614	7,536,775	11,272,389	8,470,679	1,884,194	2,457,305	35,356,957
PILs proxy from April 1, 2005 - input 9/12 of amount	+					5,528,937		5,528,937
True-up Variance Adjustment Q4, 2001 (2)	+/-		2,951					2,951
True-up Variance Adjustment (3)	+/-			221,357	-22,199	1,674,015	2,069,940	3,943,114
Deferral Account Variance Adjustment Q4, 2001 (4)	+/-		0					0
Deferral Account Variance Adjustment (5)	+/-		0	0	-404,274	-481,842	0	-886,116
Adjustments to reported prior years' variances (6)	+/-							0
LCT repeal	+/-						-126,198	-126,198
Carrying charges (7)	+/-	43,582	284,693	195,887	172,209	172,226	154,086	1,022,683
PILs billed to (collected from) customers (8)	-	0	-8,680,929	-11,019,991	-8,651,285	-8,421,372	-2,906,720	-39,680,297
Ending balance: # 1562		3,779,196	2,922,687	3,592,329	3,157,459	3,513,616	5,162,030	5,162,030

c) Please compare the results and explain where they differ from the pre-filed evidence.

Response:

The table immediately below shows the differences between the revised PILS summary continuity schedule (with interest claw-back) and the pre-filed summary continuity schedule (with interest claw-back).

	Revised 1562	Pre-filed 1562	Difference
Board-approved PILs tax proxy from Decisions	35,356,956.65	38,993,422.00	(3,636,465.35)
PILs proxy from April 1, 2005 - input 9/12 of amount	5,528,936.76	-	5,528,936.76
True-up Variance Adjustment Q4, 2001	2,951.07	-	2,951.07
True-up Variance Adjustment	401,868.41	54,922.00	346,946.41
Deferral Account Variance Adjustment Q4, 2001	-	-	-
Deferral Account Variance Adjustment	(886,115.63)	(983,305.00)	97,189.37
Adjustments to reported prior years' variances	-	-	-
LCT repeal	(126,198.00)	-	(126,198.00)
Carrying charges	584,354.93	-	584,354.93
PILs billed to (collected from) customers	(39,680,297.31)	(39,099,715.00)	(580,582.31)
Ending balance: # 1562	1,182,457	(1,034,676)	2,217,133

The upward adjustment in the PILs proxy entitlement was done to fully reflect the OEB's proxy entitlement decisions for Hydro One Brampton.

The true-up variance amounts differ because of adjustments made to the treatment of items to be trued-up compared to items to which true-up does not apply.

The difference in the deferral accounts can be attributed to adjustments to the 2001 and 2005 PILs proxy amounts, and tax rates updates.

Carrying charges as well as the repealed portion of the Federal Large Corporation Tax (LCT) were not included in the pre-filed evidence. These items have now been included.

Overall, the balance in account 1562 now reflects a receivable compared to the pre-filed balance which reflected a liability.

Ontario Energy Board Interrogatory # 72

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – PILs Account 1592

a) Please describe each type of tax item that has been accounted for in account 1592.

Response:

The following are the list of tax items that were included in account 1592.

1. Federal Large Corporation Tax (LCT) adjustment
2. Ontario Capital Tax (OCT) adjustment
3. Capital Cost Allowance (CCA) adjustment

The LCT was repealed effective January 1, 2006. Adjustment relating to 2005/2006 rates were been made in account 1562 and the 2006/2007 rate year adjustments were posted in account 1592.

b) Please provide the calculations of how each item was determined and provide any pertinent supporting evidence.

Response:

The tables below provide the calculations for each item identified in (a) above.

OCT Adjustments

	OCT in Rate Base	OCT that should have been in Rate Base	Difference	2007 Impact	2008 Impact	Total
2006 rates change (0.3% to 0.285%)	864244	821,032.00	43,212.00	14,404.00		14,404.00
2007 rates change (0.3% to 0.225%)	872195	654,146.00	218,049.00	145,366.00	72,683.00	218,049.00
				159,770.00	**72,683.00**	**232,453.00**

LCT Adjustment

LCT Provision	187,519.00
PILs adjustment	10,427.00
Total LCT	197,946.00
Tax rate	36.12%
Gross up LCT	309,871.63
Monthly amount	**25,822.64**

c) Did Hydro One Brampton follow the guidance provided in FAQ July 2007?

Response

Yes, the Company believes it has followed the guidelines.

Ontario Energy Board Interrogatory # 73

Ref: Exhibit 9 / Tab 1/ Schedule 5.0 – Disposition Methodology

In Exhibit 9/ Tab 1/ Schedule 1/ Page 1, Hydro One Brampton stated that it allocated balances to rate classes based on the default cost allocation methodology in the EDDVAR report. For account 1595 EDDVAR indicates on page 21, *"Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented."* For accounts 1562 and 1592, EDDVAR indicates, *"Case-by-case basis".*

a) Since accounts 1562 and 1592 have not been cleared for the majority of distributors, and no rate riders have been set, on which recovery share has Hydro One Brampton relied? PILs were recovered in 2002, 2003, and up to 1 March, 2004 using the fixed and variable charges. PILs amounts were unallocated to rate classes based on the distribution revenue shares from the 2001 unbundling application. The 2006 EDR allocations were also based on these same distribution revenue shares. PILs for 2004, 2005 and up to April 1, 2006 were recovered on the variable charge.

Response:

Hydro One Brampton has relied on Distribution Revenue share to allocate the PILS deferral account disposition across customer classes and the Distribution Revenue share by class was used to establish the variable rate rider. Hydro One Brampton believes Distribution Revenue share is the most appropriate allocator to determine the share by customer class as PILS was included in rates as a component of billed revenues transferred from the Distribution Revenue accounts to the PILS deferral account. Although the amounts billed to customers was based on different billing determinants for recovery from customers, the PILS rate slivers were always part of billed distribution rates which are driven by Distribution Revenue, i.e. PILS billed to customers from March 2002 to March 2004 were recovered based on fixed and variable rates, and PILS billed to customers from April 1, 2004, to March 31, 2006 were recovered based on variable rates only.

b) Has Hydro One Brampton allocated the PILs 1562 and 1592 balances to the rate classes in a consistent manner to that followed when the rates were originally created from 2001 through 2005?

Response:

Yes. PILS has been a component of revenue in rates from March 1, 2002, to April 30, 2006, and revenue was used as the basis to allocate the recovery shares by customer class.

c) Could Hydro One Brampton use the cost allocation shares from its 2008 cost of service application?

Response:

Hydro One Brampton does not believe the cost allocation shares are representative of how PILS were billed to customers. Hydro One Brampton believes the best indicator of the causality of the amount to be disposed of is what was billed to customers, rather than distribution costs allocated in the Cost Allocation Model.

d) Could Hydro One Brampton use the cost allocation shares that it has applied for in its 2011 rates application?

Reponse:

Hydro One Brampton does not believe the cost allocation shares are representative of how PILS were billed to customers. Hydro One Brampton believes the best indicator of the causality of the amount to be disposed of is what was billed to customers, rather than distribution costs allocated in the Cost Allocation Model.

e) What billing determinant(s) should be used to recover the final amount in accounts 1562 and 1592? That is, by the fixed and variable charges, fixed charge only, or variable charge only?

Response:

The variable charge only.

f) Should the final balances in accounts 1562 and 1592 that will be approved for disposition be transferred to account 1590 Recovery of Regulatory Asset Balances or account 1595? If there are separate disposition rate riders for PILs, would it make sense to transfer the balance to 1590 or 1595?

Response:

Hydro One Brampton believes that both accounts 1562 and 1563 accounts should be retained and used for the disposition of the account balances. Hydro One Brampton believes that the account balances should not be transferred to either account 1590 or 1595. Hydro One Brampton believes that account 1592 should be cleared to account 1595 along with other group two regulatory assets/liabilities.

g) Should the disposition of accounts 1562 and 1592 be made final in this proceeding? How, and if at all, should subsequent tax reassessments for the period 2001 through 2005 from the tax authorities be handled in the future?

Response:

The disposition of accounts 1562 and 1592 should be considered final in this proceeding unless subsequent reassessments from the tax authorities are material for the period 2001 through 2005. Where subsequent reassessments are significant, the Distributor would be permitted to seek disposition on a case by case basis subject to a prudency review.

EXHIBIT 12 TAB 2

ENERGY PROBE

Energy Probe Interrogatory # 1

Ref: Exhibit 1, Tab 3, Schedule 3.0

In July, 2010, the Accounting Standards Board issued an exposure draft that proposes that qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the account standards in Part V of the Handbook for an additional two years and that adoption of the IFRSs in part 1 of the Handbook by qualifying entities would be mandatory for interim and annual financial statements related to annual periods beginning on or after January 1, 2013.

If rate-regulated entities were to be granted a two year deferral on the adoption of IFRS for accounting purposes, would HOBNI agree that its revenue requirement for the 2011 test year should be estimated CGAAP rather than IFRS? If not, why not?

Response:

On September 10, 2012, the Canadian Accounting Standards Board approved the deferral option was approved as a single year delay meaning that qualifying utilities can opt to defer IFRS implementation to January 1, 2012.The Company intends to opt for this delay. As a result, HOBNI agrees that the revenue requirement for the 2011 test year will be estimated based on CGAAP. Please refer to the September 2nd letter to the Board.

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Energy Probe Interrogatory # 2

Ref: Exhibit 1, Tab 3, Schedule 3.1

a) Please confirm that the increase in the OM&A under IFRS relative to CGAAP is the result of expenses that would be capitalized under CGAAP, but not under IFRS. Other than this change in capitalization, is there any other factor contributing to the increase in OM&A under IFRS?

Response:

The increase in OM&A under IFRS is solely the result of expenditures that would be capitalized under CGAAP but not under IFRS.

b) Please confirm that the decrease in amortization expense, interest expense, PILs and return on equity are all driven by a lower rate base under IFRS relative to CGAAP. Other than the reduction in rate base (due to the change in allowed capitalization), is there any other factor contributing to the decrease in any of these items under IFRS?

Response:

There are no other factors contributing to the decreases interest expense, PILS and return on equity. The decrease in amortization expense is also due to the use of longer useful lives

Energy Probe Interrogatory # 3

Ref: Exhibit 1, Tab 3, Schedule 7.0, page 2

The evidence states that HOBNI is seeking recovery of the life-to-date revenue requirement related to capital and operating expenditures for smart meters installed to the end of 2009 and has therefore included all smart meter related costs in rate base.

a) Do the smart meter related costs related to the meters installed to the end of 2009 include any costs that are proposed to be recovered through the smart meter deferral account referenced on page 1? If yes, please explain why this is not double counting of these costs.

Response:

Yes. The smart meter costs that have been included to the end of 2009 are shown for comparative purposes only so that the 2011 Test Year costs can be compared with prior years on a like to like basis. The Trial Balances to the end of 2009 include these costs through the capital and OM&A USoA accounts. The 2011 Test Year revenue requirement includes the revenue requirement for smart meters installed to the end of 2009 only for the 2011 Test Year but does not include any recovery of revenue requirement for prior years. Revenue requirements for years prior to the 2011 Test Year are recovered through the smart meter disposition rate rider.

The Trial Balances to the end of 2009 do not include the smart meter costs that are being recovered for final disposition in the USoA smart meter deferral accounts 1555 & 1556 so as not to double count these costs in the Trial Balances to the end of 2009; however, these costs were used in the determination of the smart meter disposition rider.

b) Have the smart meter related costs that are proposed to be included in rate base for the meters installed by the end of 2009 been reduced to reflect the depreciation expense associated with these meters and included in the deferral account?

Response:

The cumulative depreciation expense to December 31, 2011 was used to reduce smart meter related capital costs when determining the 2011 Test Year rate base. The determination of the smart meter disposition rider includes the accumulated depreciation expense to the end of 2009 associated with these meters

c) Please provide a schedule showing the determination of the cost of the smart meters installed to the end of 2009 to be included in the 2011 rate base.

Smart Meter Capital Costs Included in Rate Base

Year	Smart Meter Assets Added	Cumulative Smart Meter Additions	Smart Meter Depreciation	Cumulative Smart Meter Depreciation	Net Book Value
2006	$ 65,374.09	$ 65,374.09	$ (2,179.14)	$ (2,179.14)	$ 63,194.95
2007	$ 5,246,320.61	$ 5,311,694.70	$ (179,235.63)	$ (181,414.76)	$ 5,130,279.94
2008	$ 5,908,200.88	$ 11,219,895.58	$ (551,053.01)	$ (732,467.77)	$ 10,487,427.81
2009	$ 8,663,013.96	$ 19,882,909.54	$ (1,036,760.17)	$ (1,769,227.94)	$ 18,113,681.60
2010	$ -	$ 19,882,909.54	$ (1,325,527.30)	$ (3,094,755.25)	$ 16,788,154.29
2011	$ -	$ 19,882,909.54	$ (1,325,527.30)	$ (4,420,282.55)	$ 15,462,626.99
		Average Net Book Value included in Rate Base for 2011			$ 16,125,390.64

d) Has HOBNI claimed CCA on the smart meters in the year they were purchased/installed?

Response:

HOBNI has claimed CCA on the smart meters in the year they were purchased/installed.

Energy Probe Interrogatory # 4

Ref: Exhibit 1, Tab 3, Schedule 7.0, page 2

Please explain the significance and impact of the proposed treatment of stranded meters.

Response:

In this application Hydro One Brampton has included a return on the meter capital costs that were stranded as the result of the installation of the new Smart Meters. The stranded meter costs have been included in the respective fixed asset/accumulated depreciation metering accounts for all historical years filed with this application.

Energy Probe Interrogatory # 5

Ref: Exhibit 2, Tab 2, Schedule 1

The evidence states that HOBNI has calculated the depreciation expense for the 2010 bridge year and 2011 test year using a full year's depreciation. The evidence also states that on an actual basis, depreciation commences in the month in which the asset was installed and being used for its intended purpose.

a) Please confirm that the depreciation expense recorded in each of 2006 through 2009 is not based on the full year methodology, but is based on when the assets actually went into service.

Response:

Depreciation in each of 2006 through 2009 is based on using a half-year's amortization as per the Company's policy for CGAAP

b) Please explain the rationale for using the full year depreciation methodology for 2010 and 2011?

Response:

Depreciation expense was erroneously calculated using a full year's depreciation for 2010 and 2011. This has now been corrected.

c) What is the impact on the 2011 rate base if the half-year rule was used for 2010?

Response:

HOBNI's rate base for 2010 and 2011 has been recalculated based on changes to our revenue model. This recalculation includes the effect of the half year rule.

d) What is the impact on the 2011 depreciation expense if the half-year rule was applied to 2010 and 2011?

Response:

Depreciation expense has been re-calculated to include the half-year rule in 2010 and 2011. The impact on the 2011 depreciation expense if the half-year rule was applied to 2010 and 2011 would be a decrease of approximately $0.5 million.

Energy Probe Interrogatory # 6

Ref: Exhibit 2, Tab 2, Schedules 1.1 and 1.2

a) Please explain why no disposals have been forecast for 2010 or 2011 despite the fact that in each of 2006 through 2010, gross asset disposals have been larger than the corresponding disposals shown for accumulated depreciation.

Response:

The forecast process at HOBNI revolves mostly around capital spending. In historical years, disposals mostly involve vehicles, line transformers and sales of equipment. Disposed vehicles have a negligible net book value, and therefore their disposal has no effect on rate base. Line transformer disposals are as a direct result of accidents, which are unpredictable. Sales of equipment happen very rarely. For those reasons, they are not included in the forecast process.

b) Has HOBNI disposed of any assets as of the most recent information available for 2010? If yes, please provide the amount for each account for each of the following:

i) the disposal amount related to cost;

ii) the disposal amount related to accumulated depreciation; and,

iii) the gain or loss as a result of the disposals.

Response:

HOBNI has disposed of assets due to accidents and sales of vehicles as of June 30, 2010:

Account	Original Cost	Accumulated Depreciation	NBV	Proceeds	Gain (Losss)
1830	10,251	9,513	738	738	-
1850	16,465	14,639	1,825	1,825	-
1930	140,521	140,521	-	5,624	5,624
Total	167,237	164,674	2,564	8,187	5,624

c) Please indicate the specific assets included in account 1610 - Miscellaneous Intangible Plant - TS and account 1610- Miscellaneous Intangible Plant - Software. Why are these assets included in account 1610 rather than in another account?

Response:

The specific assets in account 1610 Miscellaneous Intangible Plant – TS are capital contributions paid related to the Goreway Transformer Station and the Pleasant Transformer Station. The specific assets in account 1610 Miscellaneous Intangible Plant – Software are applications software assets not directly required to operate other tangible capital assets.

These assets are included in account 1610 rather than in another account because effective January 1, 2009, the Company adopted CICA Handbook Section 3064, Goodwill and Intangible Assets, which replaced CICA Handbook Section 3062, Goodwill and Other Intangible Assets, and CICA Handbook Section 3450, Research and Development Costs. The new section establishes standards for the recognition,

measurement, presentation and disclosure of goodwill and other intangible assets. Upon adoption of the new accounting standard, on January 1, 2009, the Company reclassified some computer applications software and capital contributions to Hydro One Networks previously classified as fixed assets to intangible assets.

d) Please explain the substantial reduction in contributions and grants forecast for 2010 ($9.8 million) in comparison to the $12.7 million recorded in 2009, $16.1 million in 2008 and $18.5 million in 2007.

Response:

The 2010 forecast was calculated based on IFRS. Previous year forecasting was based on Generally Accepted Accounting Principles (GAAP).

As a comparison, the 2010 forecast utilizing GAAP would amount to $11.6 million.

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Energy Probe Interrogatory # 7

Ref: Exhibit 2, Tab 2, Schedule 1.2

Table 1 appears to be incorrect in that the opening balance shown under cost for 2010 is equal to the 2009 net book value rather than the 2009 closing balance for cost. Similarly, the opening balance under accumulated depreciation reflects no accumulated depreciation rather than showing the closing balance for 2009. These changes then appear to be carried on into Table 2 for 2011.

a) Please provide revised Tables 1 & 2 that reflect the closing balances from 2009 carried forward as the opening balances for 2010 for both costs and accumulated depreciation.

Response:

The revised Table 1 and 2 reflects the closing balances from 2009 carried forward as the opening balances for 2010 for both costs and accumulated depreciation. Please note that the fixed asset continuity now reflects CGAAP additions for both 2010 and 2011, and now reflect the use of the ½ year rule for both years, using old useful lives for 2010 and new useful lives for 2011, according to the September 30 letter.

Exhibit 2, Tab 2, Schedule 1.2, Table 1: Forecast Fixed Asset Continuity Schedule 2010

			Cost					Accumulated Depreciation					
OEB	Account description	Depreciation Rate	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Net Book Value
1805	Land	-	8,146,892	-	-	-	8,146,892	-	-	-	-	-	8,146,892
1806	Land Rights	various	1,412,508	383,000	-	(33,300)	1,762,208	(220,964)	(4,523)	-	-	(225,487)	1,536,720
1808	Buildings and Fixtures	various	29,478,774	435,898	-		29,914,672	(8,556,449)	(591,106)	-	-	(9,147,555)	20,767,117
1815	Transformer Station Equipment - Normally Primary above 50 kV	various	12,011,917	814,102	-	(154,746)	12,671,273	(2,112,335)	(395,503)	-	-	(2,507,838)	10,163,435
1820	Distribution Station Equipment - Normally Primary below 50 kV	various	40,492,279	1,222,000	-	(105,400)	41,608,879	(27,932,761)	(1,355,438)	-	-	(29,288,199)	12,320,680
1830	Poles, Towers and Fixtures	25	61,098,800	7,455,828	-	(743,292)	67,811,336	(21,713,492)	(2,396,131)	-	-	(24,109,623)	43,701,713
1835	Overhead Conductors and Devices	25	19,376,229	1,988,000	-	(197,165)	21,167,064	(3,732,776)	(795,913)	-	-	(4,528,689)	16,638,375
1840	Underground Conduit	25	17,738,414	3,441,345	-	(342,664)	20,837,095	(2,494,932)	(740,536)	-	-	(3,235,468)	17,601,627
1845	Underground Conductors and Devices	25	215,034,537	11,303,857	-	(1,124,981)	225,213,413	(94,946,248)	(8,268,775)	-	-	(103,215,023)	121,998,389
1850	Line Transformers	25	88,592,205	4,860,014	-	(483,452)	92,968,767	(43,851,426)	(3,195,173)	-	-	(47,046,600)	45,922,168
1855	Services	25	23,014,363	661,552	-	-	23,675,915	(11,908,672)	(892,740)	-	-	(12,801,411)	10,874,504
1860	Meters	various	43,203,730	1,026,750	-	-	44,230,480	(15,045,559)	(1,720,674)	-	(325,000)	(17,091,233)	27,139,247
1908	Buildings and Fixtures	25	310,348	-	-	-	310,348	(33,853)	(12,289)	-	-	(46,141)	264,207
1915	Office Furniture and Equipment	10	1,702,247	528,000	-	-	2,230,247	(1,581,833)	(63,118)	-	-	(1,644,951)	585,295
1920	Computer Equipment - Hardware	5	3,199,798	840,400	-	-	4,040,198	(2,846,894)	(265,618)	-	-	(3,112,511)	927,687
1925	Computer Software	5	-	-	-	-	-	-	-	-	-	-	-
1930	Transportation Equipment	various	9,376,602	1,980,000	-	-	11,356,602	(5,981,990)	(704,519)	-	-	(6,686,509)	4,670,092
1935	Stores Equipment	10	219,670	-	-	-	219,670	(120,212)	(16,339)	-	-	(136,551)	83,119
1940	Tools, Shop and Garage Equipment	10	2,847,869	381,000	-	-	3,228,869	(1,999,230)	(159,804)	-	-	(2,159,034)	1,069,835
1950	Power Operated Equipment	8	37,250	-	-	-	37,250	(24,835)	(4,486)	-	-	(29,321)	7,929
1955	Communication Equipment	10	605,068	41,600	-	-	646,668	(183,893)	(62,587)	-	-	(246,479)	400,188
1960	Miscellaneous Equipment	10	140,957	-	-	-	140,957	(58,716)	(14,098)	-	-	(72,814)	68,142
1980	System Supervisory Equipment	15	4,511,464	101,000	-	-	4,612,464	(3,219,842)	(191,915)	-	-	(3,411,756)	1,200,708
1995	Contributions and Grants - Credit	25	(100,287,257)	(11,627,427)	-	(31,066)	(111,945,750)	17,221,643	3,706,725	-	-	20,928,368	(91,017,383)
			482,264,663	25,836,919	-	(3,216,066)	504,885,516	(231,345,270)	(18,144,560)	-	(325,000)	(249,814,830)	255,070,686
2055	Construction Work in Progress--Electric	none	798,274	-	-	3,216,066	4,014,340	-	-	-	-	-	4,014,340
			483,062,937	25,836,919	-	-	508,899,856	(231,345,270)	(18,144,560)	-	(325,000)	(249,814,830)	259,085,026
2040	Electric Plant Held for Future Use	None	3,369,797	-	-	-	3,369,797	-	-	-	-	-	3,369,797
1610	Miscellaneous Intangible Plant - TS CIP	none	5,118,257		-	(5,118,257)	-	-		-	-	-	-
1610	Miscellaneous Intangible Plant - Software CIP	none	84,843	-	-	(84,843)	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - TS in-service	various	3,045,640	5,268,063	-	5,118,257	13,431,960	(117,463)	(204,165)	-	-	(321,627)	13,110,333
1610	Miscellaneous Intangible Plant - Software in-service	various	1,940,555	961,600	-	84,843	2,986,998	(1,249,045)	(285,563)	-	-	(1,534,608)	1,452,390
			10,189,295	6,229,663	-	0	16,418,958	(1,366,507)	(489,728)	-	-	(1,856,235)	14,562,722
	Total		496,622,029	32,066,582	-	0	528,688,611	(232,711,777)	(18,634,288)	-	(325,000)	(251,671,065)	277,017,545

The revised Table 2 reflects the changes affected by the closing balances from 2009 carried forward as the opening balances for 2010 for both costs and accumulated depreciation:

Exhibit 2, Tab 2, Schedule 1.2, Table 2: Forecast Fixed Asset Continuity Schedule 2011

			Cost					Accumulated Depreciation					
OEB	Account description	Depreciation Rate	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Opening Balance	Additions	Disposals	Adjustments	Closing Balance	Net Book Value
1805	Land	-	8,146,892	-	-	-	8,146,892	-	-	-	-	-	8,146,892
1806	Land Rights	various	1,762,208	192,000	-	16,600	1,970,808	(225,487)	(10,106)	-	-	(235,593)	1,735,214
1808	Buildings and Fixtures	50	29,914,672	970,650	-	(45,127)	30,840,195	(9,147,555)	(613,562)	-	-	(9,761,118)	21,079,077
1815	Transformer Station Equipment - Normally Primary above 50 kV	40	12,671,273	1,643,000	-	23,324	14,337,597	(2,507,838)	(447,576)	-	-	(2,955,414)	11,382,183
1820	Distribution Station Equipment - Normally Primary below 50 kV	40	41,608,879	913,000	-	58,404	42,580,283	(29,288,199)	(582,974)	-	-	(29,871,173)	12,709,110
1830	Poles, Towers and Fixtures	42	67,811,336	5,268,405	-	435,436	73,515,177	(24,109,623)	(1,298,927)	-	-	(25,408,551)	48,106,626
1835	Overhead Conductors and Devices	50	21,167,064	924,000	-	143,069	22,234,133	(4,528,689)	(377,459)	-	-	(4,906,148)	17,327,985
1840	Underground Conduit	50	20,837,095	3,509,502	-	137,548	24,484,145	(3,235,468)	(416,318)	-	-	(3,651,786)	20,832,359
1845	Underground Conductors and Devices	35	225,213,413	13,350,056	-	351,588	238,915,057	(103,215,023)	(5,433,684)	-	-	(108,648,708)	130,266,349
1850	Line Transformers	40	92,968,767	6,123,387	-	129,057	99,221,211	(47,046,600)	(1,589,692)	-	-	(48,636,291)	50,584,920
1855	Services	50	23,675,915	767,000	-	-	24,442,915	(12,801,411)	(282,225)	-	-	(13,083,637)	11,359,278
1860	Meters	15	44,230,480	991,000	-	-	45,221,480	(17,091,233)	(1,761,151)	-	(390,000)	(19,242,383)	25,979,097
1908	Buildings and Fixtures	25	310,348	-	-	-	310,348	(46,141)	(12,289)	-	-	(58,430)	251,918
1915	Office Furniture and Equipment	10	2,230,247	168,475	-	-	2,398,722	(1,644,951)	(97,382)	-	-	(1,742,333)	656,389
1920	Computer Equipment - Hardware	5	4,040,198	305,200	-	-	4,345,398	(3,112,511)	(293,602)	-	-	(3,406,114)	939,284
1925	Computer Software	5	-	-	-	-	-	-	-	-	-	-	-
1930	Transportation Equipment	various	11,356,602	2,294,478	-	-	13,651,080	(6,686,509)	(917,569)	-	-	(7,604,079)	6,047,001
1935	Stores Equipment	10	219,670	-	-	-	219,670	(136,551)	(16,339)	-	-	(152,890)	66,780
1940	Tools, Shop and Garage Equipment	10	3,228,869	104,962	-	-	3,333,831	(2,159,034)	(167,201)	-	-	(2,326,235)	1,007,596
1950	Power Operated Equipment	8	37,250	-	-	-	37,250	(29,321)	(4,486)	-	-	(33,807)	3,443
1955	Communication Equipment	10	646,668	133,400	-	-	780,068	(246,479)	(71,337)	-	-	(317,816)	462,252
1960	Miscellaneous Equipment	10	140,957	-	-	-	140,957	(72,814)	(14,098)	-	-	(86,913)	54,044
1980	System Supervisory Equipment	7	4,612,464	501,000	-	-	5,113,464	(3,411,756)	(683,502)	-	-	(4,095,259)	1,018,205
1995	Contributions and Grants - Credit	35	(111,945,750)	(14,598,572)	-	11,542	(126,532,780)	20,928,368	3,049,765	-	-	23,978,133	(102,554,647)
			504,885,516	23,560,943	-	1,261,441	529,707,900	(249,814,830)	(12,041,713)	-	(390,000)	(262,246,542)	267,461,358
2055	Construction Work in Progress--Electric	None	4,014,340	-	-	(1,261,441)	2,752,899	-	-	-	-	-	2,752,899
			508,899,856	23,560,943	-	-	532,460,799	(249,814,830)	(12,041,713)	-	(390,000)	(262,246,542)	270,214,256
2040	Electric Plant Held for Future Use	None	3,369,797	-	-	-	3,369,797	-	-	-	-	-	3,369,797
1610	Miscellaneous Intangible Plant - TS CIP	None	-	-	-	-	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - Software CIP	None	-	-	-	-	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - TS in-service	various	13,431,960	-	-	-	13,431,960	(321,627)	(332,189)	-	-	(653,816)	12,778,144
1610	Miscellaneous Intangible Plant - Software in-service	various	2,986,998	554,800	-	-	3,541,798	(1,534,608)	(238,810)	-	-	(1,773,418)	1,768,380
			16,418,958	554,800	-	-	16,973,758	(1,856,235)	(570,998)	-	-	(2,427,234)	14,546,524
	Total		528,688,611	24,115,743	-	-	552,804,354	(251,671,065)	(12,612,711)	-	(390,000)	(264,673,776)	288,130,577

b) Please provide revised versions of any tables elsewhere in the evidence impacted by this change.

Response:

The following tables are revised versions impacted by the change:

Exhibit 2, Tab 2, Schedule 2, Table 1: Fixed Asset Variance 2006 - 2011

OEB #	Description	2006 Board Approved ($)	2006 Actual ($)	Variance form 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Actual ($)	Variance from 2008 Actual	2010 Bridge ($)	Variance from 2009 Actual	2011 Test ($)	Variance from 2010 Bridge
	Land and Buildings													
1805	Land	8,191,402	8,146,892	(44,510)	8,146,892	-	8,146,892	-	8,146,892	-	8,146,892	-	8,146,892	-
1806	Land Rights	998,488	1,363,044	364,555	1,382,214	19,170	1,389,282	7,069	1,412,508	23,226	1,762,208	349,700	1,970,808	208,600
1808	Buildings and Fixtures	21,077,814	26,272,435	5,194,621	27,903,094	1,630,659	29,186,650	1,283,556	29,478,774	292,124	29,914,672	435,898	30,840,195	925,523
1908	Buildings and Fixtures		-	-	-	-	-	-	310,348	310,348	310,348	-	310,348	-
	Subtotal - Land and Buildings	30,267,704	35,782,370	5,514,666	37,432,199	1,649,829	38,722,824	1,290,625	39,348,522	625,698	40,134,120	785,598	41,268,243	1,134,123
	Distribution Systems													
1815	Transformer Station Equipment - Normally Primary above 50 kV	13,546,126	10,680,767	(2,865,359)	10,693,367	12,600	14,929,647	4,236,279	12,011,917	(2,917,730)	12,671,273	659,356	14,337,597	1,666,324
1820	Distribution Station Equipment - Normally Primary below 50 kV	39,866,293	40,830,304	964,011	41,022,337	192,033	40,212,984	(809,353)	40,492,279	279,295	41,608,879	1,116,600	42,580,283	971,404
	Subtotal - Distributions Systems	53,412,419	51,511,071	(1,901,347)	51,715,705	204,633	55,142,631	3,426,927	52,504,196	(2,638,435)	54,280,152	1,775,956	56,917,880	2,637,728
	Poles and Wires													
1830	Poles, Towers and Fixtures	32,481,555	43,804,228	11,322,674	49,581,714	5,777,486	53,969,895	4,388,180	61,098,800	7,128,905	67,811,336	6,712,536	73,515,177	5,703,841
1835	Overhead Conductors and Devices	7,522,161	13,105,220	5,583,060	15,088,531	1,983,311	17,162,086	2,073,555	19,376,229	2,214,142	21,167,064	1,790,835	22,234,133	1,067,069
1840	Underground Conduit	4,211,008	9,027,188	4,816,180	11,129,854	2,102,665	13,073,275	1,943,421	17,738,414	4,665,139	20,837,095	3,098,681	24,484,145	3,647,050
1845	Underground Conductors and Devices	149,028,184	167,712,557	18,684,373	191,157,922	23,445,365	207,302,793	16,144,870	215,034,537	7,731,744	225,213,413	10,178,876	238,915,057	13,701,644
	Subtotal - Poles and Wires	193,242,907	233,649,194	40,406,287	266,958,022	33,308,828	291,508,049	24,550,027	313,247,979	21,739,931	335,028,907	21,780,928	359,148,511	24,119,604
	Line Transformers													
1850	Line Transformers	66,129,151	74,768,688	8,639,536	77,047,361	2,278,674	82,393,441	5,346,080	88,592,205	6,198,764	92,968,767	4,376,562	99,221,211	6,252,444
	Subtotal - Line Transformers	66,129,151	74,768,688	8,639,536	77,047,361	2,278,674	82,393,441	5,346,080	88,592,205	6,198,764	92,968,767	4,376,562	99,221,211	6,252,444
	Services and Meters													
1855	Services	18,875,683	21,062,746	2,187,064	21,856,284	793,538	22,400,827	544,543	23,014,363	613,536	23,675,915	661,552	24,442,915	767,000
1860	Meters	18,796,314	21,208,772	2,412,458	27,365,957	6,157,185	33,758,650	6,392,693	43,203,730	9,445,080	44,230,480	1,026,749	45,221,480	991,000
	Subtotal - Services and Meters	37,671,996	42,271,518	4,599,522	49,222,241	6,950,723	56,159,477	6,937,236	66,218,093	10,058,616	67,906,395	1,688,301	69,664,395	1,758,000
	IT Assets													
1920	Computer Equipment - Hardware	1,441,891	3,295,561	1,853,670	3,772,019	476,458	3,927,472	155,453	3,199,798	(727,675)	4,040,198	840,400	4,345,398	305,200
1925	Computer Software		420,970	420,970	929,876	508,907	1,113,908	184,032	-	(1,113,908)	-	-	-	-
	Subtotal - IT Assets	1,441,891	3,716,531	2,274,640	4,701,896	985,365	5,041,381	339,485	3,199,798	(1,841,583)	4,040,198	840,400	4,345,398	305,200
	Equipment													
1915	Office Furniture and Equipment	1,307,532	1,528,785	221,253	1,615,311	86,526	1,699,677	84,367	1,702,247	2,570	2,230,247	528,000	2,398,722	168,475
1930	Transportation Equipment	6,442,515	7,408,450	965,935	8,415,834	1,007,384	8,467,628	51,794	9,376,602	908,973	11,356,602	1,980,000	13,651,080	2,294,478
1935	Stores Equipment	-	219,670	219,670	219,670	0	219,670	0	219,670	-	219,670	-	219,670	-
1940	Tools, Shop and Garage Equipment	1,841,837	2,244,536	402,698	2,532,072	287,536	2,688,833	156,761	2,847,869	159,036	3,228,869	381,000	3,333,831	104,962
1950	Power Operated Equipment	-	37,250	37,250	37,250	0	37,250	(0)	37,250	-	37,250	-	37,250	-
1960	Miscellaneous Equipment	1,288	132,634	131,346	148,254	15,620	145,138	(3,116)	140,982	(4,156)	140,957	(25)	140,957	-
1955	Communication Equipment	56,874	294,254	237,380	396,282	102,028	475,040	78,757	605,068	130,028	646,668	41,600	780,068	133,400
1980	System Supervisory Equipment	3,588,921	4,054,722	465,802	4,263,277	208,555	4,446,485	183,208	4,511,464	64,979	4,612,464	101,000	5,113,464	501,000
	Subtotal - Equipment	13,238,967	15,920,301	2,681,334	17,627,950	1,707,649	18,179,722	551,771	19,441,152	1,261,430	22,472,727	3,031,575	25,675,042	3,202,315
	Other General Assets													
1995	Contributions and Grants - Credit	(36,117,714)	(52,971,809)	(16,854,095)	(71,500,020)	(18,528,211)	(87,582,820)	(16,082,800)	(100,287,257)	(12,704,438)	(111,945,750)	(11,658,493)	(126,532,780)	(14,587,030)
2055	Construction Work in Progress--Electric	-	682,425	682,425	2,646,633	1,964,208	1,248,887	(1,397,746)	798,274	(450,614)	4,014,340	3,216,066	2,752,899	(1,261,441)
2040	Electric Plant Held for Future Use	-	-	-	-	-	3,111,465	3,111,465	3,369,797	258,332	3,369,797	-	3,369,797	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	-	-	-	-	5,118,257	5,118,257	-	(5,118,257)	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	-	-	-	-	84,843	84,843	-	(84,843)	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	-	-	-	-	3,045,640	3,045,640	13,431,960	10,386,320	13,431,960	-
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	-	-	-	-	1,940,555	1,940,555	2,986,998	1,046,442	3,541,798	554,800
	Subtotal - Other General Assets	(36,117,714)	(52,289,384)	(16,171,670)	(68,853,386)	(16,564,003)	(83,222,467)	(14,369,081)	(85,929,891)	(2,707,424)	(88,142,656)	(2,212,764)	(103,436,327)	(15,293,671)
	TOTAL	359,287,322	405,330,289	46,042,967	435,851,987	30,521,699	463,925,058	28,073,070	496,622,055	32,696,997	528,688,611	32,066,556	552,804,354	24,115,743

Exhibit 2, Tab 2, Schedule 3, Table 1: Gross Asset Breakdown 2006 - 2011

Gross Assets	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Distribution Plant	350,456,474	437,982,841	482,375,528	523,926,423	559,910,996	590,318,341	626,220,240
General Plant	44,948,562	19,636,832	22,329,846	23,221,102	22,640,950	26,512,925	30,020,440
Contributions and Grants	(36,117,714)	(52,971,809)	(71,500,020)	(87,582,820)	(100,287,257)	(111,945,750)	(126,532,780)
Other Plant	-	682,425	2,646,633	4,360,352	14,357,366	23,803,094	23,096,453
Total	359,287,322	405,330,289	435,851,987	463,925,058	496,622,055	528,688,611	552,804,354

Exhibit 2, Tab 2, Schedule 4, Table 1:

OEB #	Description	2006 Board Approved ($)	2006 Actual ($)	2007 Actual ($)	2008 Actual ($)	2009 Actual ($)	2010 Bridge ($)	2011 Test ($)
	Land and Buildings							
1805	Land	8,191,402	8,146,892	8,146,892	8,146,892	8,146,892	8,146,892	8,146,892
1806	Land Rights	998,488	1,363,044	1,382,214	1,389,282	1,412,508	1,762,208	1,970,808
1808	Buildings and Fixtures	21,077,814	26,272,435	27,903,094	29,186,650	29,478,774	29,914,672	30,840,195
1908	Buildings and Fixtures		-	-	-	310,348	310,348	310,348
	Subtotal - Land and Buildings	30,267,704	35,782,370	37,432,199	38,722,824	39,348,522	40,134,120	41,268,243
	Distribution Systems							
1815	Transformer Station Equipment - Normally Primary above 50 kV	13,546,126	10,680,767	10,693,367	14,929,647	12,011,917	12,671,273	14,337,597
1820	Distribution Station Equipment - Normally Primary below 50 kV	39,866,293	40,830,304	41,022,337	40,212,984	40,492,279	41,608,879	42,580,283
	Subtotal - Distributions Systems	53,412,419	51,511,071	51,715,705	55,142,631	52,504,196	54,280,152	56,917,880
	Poles and Wires							
1830	Poles, Towers and Fixtures	32,481,555	43,804,228	49,581,714	53,969,895	61,098,800	67,811,336	73,515,177
1835	Overhead Conductors and Devices	7,522,161	13,105,220	15,088,531	17,162,086	19,376,229	21,167,064	22,234,133
1840	Underground Conduit	4,211,008	9,027,188	11,129,854	13,073,275	17,738,414	20,837,095	24,484,145
1845	Underground Conductors and Devices	149,028,184	167,712,557	191,157,922	207,302,793	215,034,537	225,213,413	238,915,057
	Subtotal - Poles and Wires	193,242,907	233,649,194	266,958,022	291,508,049	313,247,979	335,028,907	359,148,511
	Line Transformers							
1850	Line Transformers	66,129,151	74,768,688	77,047,361	82,393,441	88,592,205	92,968,767	99,221,211
	Subtotal - Line Transformers	66,129,151	74,768,688	77,047,361	82,393,441	88,592,205	92,968,767	99,221,211
	Services and Meters							
1855	Services	18,875,683	21,062,746	21,856,284	22,400,827	23,014,363	23,675,915	24,442,915
1860	Meters	18,796,314	21,208,772	27,365,957	33,758,650	43,203,730	44,230,480	45,221,480
	Subtotal - Services and Meters	37,671,996	42,271,518	49,222,241	56,159,477	66,218,093	67,906,395	69,664,395
	IT Assets							
1920	Computer Equipment - Hardware	1,441,891	3,295,561	3,772,019	3,927,472	3,199,798	4,040,198	4,345,398
1925	Computer Software		420,970	929,876	1,113,908	-	-	-
	Subtotal - IT Assets	1,441,891	3,716,531	4,701,896	5,041,381	3,199,798	4,040,198	4,345,398
	Equipment							
1915	Office Furniture and Equipment	1,307,532	1,528,785	1,615,311	1,699,677	1,702,247	2,230,247	2,398,722
1930	Transportation Equipment	6,442,515	7,408,450	8,415,834	8,467,628	9,376,602	11,356,602	13,651,080
1935	Stores Equipment	-	219,670	219,670	219,670	219,670	219,670	219,670
1940	Tools, Shop and Garage Equipment	1,841,837	2,244,536	2,532,072	2,688,833	2,847,869	3,228,869	3,333,831
1950	Power Operated Equipment	-	37,250	37,250	37,250	37,250	37,250	37,250
1960	Miscellaneous Equipment	1,288	132,634	148,254	145,138	140,982	140,957	140,957
1955	Communication Equipment	56,874	294,254	396,282	475,040	605,068	646,668	780,068
1980	System Supervisory Equipment	3,588,921	4,054,722	4,263,277	4,446,485	4,511,464	4,612,464	5,113,464
	Subtotal - Equipment	13,238,967	15,920,301	17,627,950	18,179,722	19,441,152	22,472,727	25,675,042
	Other General Assets							
1995	Contributions and Grants - Credit	(36,117,714)	(52,971,809)	(71,500,020)	(87,582,820)	(100,287,257)	(111,945,750)	(126,532,780)
2055	Construction Work in Progress--Electric	-	682,425	2,646,633	1,248,887	798,274	4,014,340	2,752,899
2040	Electric Plant Held for Future Use	-	-	-	3,111,465	3,369,797	3,369,797	3,369,797
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	-	5,118,257	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	-	84,843	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	-	3,045,640	13,431,960	13,431,960
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	-	1,940,555	2,986,998	3,541,798
	Subtotal - Other General Assets	(36,117,714)	(52,289,384)	(68,853,386)	(83,222,467)	(85,929,891)	(88,142,656)	(103,436,327)
	TOTAL	359,287,322	405,330,289	435,851,987	463,925,058	496,622,055	528,688,611	552,804,354

Exhibit 2, Tab 3, Schedule 2, Table 1: Accumulated Depreciation Variance 2006 - 2011

OEB #	Description	2006 Board Approved ($)	2006 Actual ($)	Variance form 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Actual ($)	Variance from 2008 Actual	2010 Bridge ($)	Variance from 2009 Actual	2011 Test ($)	Variance from 2010 Bridge
	Land and Buildings													
1805	Land	-	-	-	-	-	-	-	-	-	-		-	
1806	Land Rights	(109,292)	(166,287)	(56,995)	(193,737)	(27,450)	(219,938)	(26,201)	(220,964)	(1,026)	(225,487)	(4,523)	(235,593)	(10,106)
1808	Buildings and Fixtures	(5,429,331)	(6,713,666)	(1,284,334)	(7,299,371)	(585,705)	(7,931,278)	(631,907)	(8,556,449)	(625,172)	(9,147,555)	(591,106)	(9,761,118)	(613,562)
1908	Buildings and Fixtures	-	-	-	-	-	-	-	(33,853)	(33,853)	(46,141)	(12,289)	(58,430)	(12,289)
	Subtotal - Land and Buildings	(5,538,623)	(6,879,953)	(1,341,330)	(7,493,108)	(613,156)	(8,151,216)	(658,108)	(8,811,266)	(660,050)	(9,419,184)	(607,918)	(10,055,141)	(635,957)
	Distribution Systems													
1815	Transformer Station Equipment - Normally Primary above 50 kV	(689,235)	(1,262,667)	(573,432)	(1,529,843)	(267,177)	(1,855,250)	(325,407)	(2,112,335)	(257,085)	(2,507,838)	(395,503)	(2,955,414)	(447,576)
1820	Distribution Station Equipment - Normally Primary below 50 kV	(20,074,574)	(24,007,113)	(3,932,539)	(25,600,763)	(1,593,650)	(26,570,489)	(969,725)	(27,932,761)	(1,362,273)	(29,288,199)	(1,355,438)	(29,871,173)	(582,974)
	Subtotal - Distributions Systems	(20,763,809)	(25,269,780)	(4,505,971)	(27,130,607)	(1,860,827)	(28,425,739)	(1,295,132)	(30,045,096)	(1,619,357)	(31,796,037)	(1,750,941)	(32,826,587)	(1,030,550)
	Poles and Wires													
1830	Poles, Towers and Fixtures	(12,285,704)	(15,809,144)	(3,523,440)	(17,600,560)	(1,791,415)	(19,560,024)	(1,959,464)	(21,713,492)	(2,153,468)	(24,109,623)	(2,396,131)	(25,408,551)	(1,298,927)
1835	Overhead Conductors and Devices	(887,664)	(1,793,123)	(905,459)	(2,356,997)	(563,875)	(3,002,010)	(645,012)	(3,732,776)	(730,766)	(4,528,689)	(795,913)	(4,906,148)	(377,459)
1840	Underground Conduit	(408,730)	(990,442)	(581,712)	(1,393,582)	(403,141)	(1,878,699)	(485,116)	(2,494,932)	(616,234)	(3,235,468)	(740,536)	(3,651,786)	(416,318)
1845	Underground Conductors and Devices	(57,765,971)	(72,550,839)	(14,784,869)	(79,399,893)	(6,849,054)	(86,955,712)	(7,555,819)	(94,946,248)	(7,990,536)	(103,215,023)	(8,268,775)	(108,648,708)	(5,433,684)
	Subtotal - Poles and Wires	(71,348,069)	(91,143,548)	(19,795,479)	(100,751,032)	(9,607,484)	(111,396,444)	(10,645,412)	(122,887,449)	(11,491,005)	(135,088,804)	(12,201,355)	(142,615,192)	(7,526,388)
	Line Transformers													
1850	Line Transformers	(29,144,974)	(35,276,009)	(6,131,035)	(37,969,885)	(2,693,877)	(40,787,600)	(2,817,715)	(43,851,426)	(3,063,826)	(47,046,600)	(3,195,173)	(48,636,291)	(1,589,692)
	Subtotal - Line Transformers	(29,144,974)	(35,276,009)	(6,131,035)	(37,969,885)	(2,693,877)	(40,787,600)	(2,817,715)	(43,851,426)	(3,063,826)	(47,046,600)	(3,195,173)	(48,636,291)	(1,589,692)
	Services and Meters													
1855	Services	(7,490,844)	(9,360,196)	(1,869,352)	(10,184,127)	(823,930)	(11,034,819)	(850,692)	(11,908,672)	(873,853)	(12,801,411)	(892,740)	(13,083,637)	(282,225)
1860	Meters	(9,145,090)	(11,032,497)	(1,887,408)	(12,025,839)	(993,342)	(13,306,627)	(1,280,788)	(15,045,559)	(1,738,932)	(17,091,233)	(2,045,674)	(19,242,383)	(2,151,151)
	Subtotal - Services and Meters	(16,635,934)	(20,392,694)	(3,756,760)	(22,209,966)	(1,817,272)	(24,341,445)	(2,131,480)	(26,954,230)	(2,612,785)	(29,892,644)	(2,938,414)	(32,326,020)	(2,433,376)
	IT Assets													
1920	Computer Equipment - Hardware	(975,686)	(1,865,000)	(889,314)	(2,427,570)	(562,571)	(3,011,758)	(584,187)	(2,846,894)	164,864	(3,112,511)	(265,618)	(3,406,114)	(293,602)
1925	Computer Software	(5,544)	(81,206)	(75,662)	(216,291)	(135,085)	(420,605)	(204,314)	-	420,605	-	-	-	-
	Subtotal - IT Assets	(981,230)	(1,946,206)	(964,976)	(2,643,861)	(697,655)	(3,432,363)	(788,502)	(2,846,894)	585,469	(3,112,511)	(265,618)	(3,406,114)	(293,602)
	Equipment													
1915	Office Furniture and Equipment	(1,264,636)	(1,455,977)	(191,342)	(1,509,009)	(53,032)	(1,544,092)	(35,083)	(1,581,833)	(37,741)	(1,644,951)	(63,118)	(1,742,333)	(97,382)
1930	Transportation Equipment	(4,153,071)	(4,901,863)	(748,793)	(5,085,625)	(183,761)	(5,519,688)	(434,064)	(5,981,990)	(462,302)	(6,686,509)	(704,519)	(7,604,079)	(917,569)
1935	Stores Equipment	(12,486)	(65,567)	(53,082)	(87,535)	(21,967)	(103,873)	(16,338)	(120,212)	(16,339)	(136,551)	(16,339)	(152,890)	(16,339)
1940	Tools, Shop and Garage Equipment	(1,223,937)	(1,542,658)	(318,721)	(1,701,152)	(158,494)	(1,852,850)	(151,698)	(1,999,230)	(146,381)	(2,159,034)	(159,804)	(2,326,235)	(167,201)
1950	Power Operated Equipment	2,212	(11,375)	(13,587)	(15,862)	(4,486)	(20,348)	(4,487)	(24,835)	(4,486)	(29,321)	(4,486)	(33,807)	(4,486)
1960	Miscellaneous Equipment	(1,642)	(20,133)	(18,490)	(34,177)	(14,044)	(45,682)	(11,505)	(58,716)	(13,035)	(72,814)	(14,098)	(86,913)	(14,098)
1955	Communication Equipment	(6,727)	(51,819)	(45,093)	(86,346)	(34,527)	(129,912)	(43,566)	(183,893)	(53,980)	(246,479)	(62,587)	(317,816)	(71,337)
1980	System Supervisory Equipment	(2,118,228)	(2,600,686)	(482,457)	(2,805,428)	(204,742)	(3,012,483)	(207,055)	(3,219,842)	(207,359)	(3,411,756)	(191,915)	(4,095,259)	(683,502)
	Subtotal - Equipment	(8,778,514)	(10,650,080)	(1,871,565)	(11,325,133)	(675,053)	(12,228,928)	(903,795)	(13,170,551)	(941,623)	(14,387,417)	(1,216,866)	(16,359,331)	(1,971,914)
	Other General Assets													
1995	Contributions and Grants - Credit	3,898,110	7,793,148	3,895,039	10,282,585	2,489,437	13,464,242	3,181,657	17,221,643	3,757,402	20,928,368	3,706,725	23,978,133	3,049,765
2055	Construction Work in Progress--Electric	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	Electric Plant Held for Future Use	-	-	-	-	-	-	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	-	-	-	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	-	-	-	-	-	-	-	-	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	-	-	-	-	(117,463)	(117,463)	(321,627)	(204,165)	(653,816)	(332,189)
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	-	-	-	-	(1,249,045)	(1,249,045)	(1,534,608)	(285,563)	(1,773,418)	(238,810)
	Subtotal - Other General Assets	3,898,110	7,793,148	3,895,039	10,282,585	2,489,437	13,464,242	3,181,657	15,855,136	2,390,894	19,072,132	3,216,997	21,550,899	2,478,767
	TOTAL	(149,293,043)	(183,765,121)	(34,472,078)	(199,241,008)	(15,475,887)	(215,299,494)	(16,058,486)	(232,711,777)	(17,412,283)	(251,671,065)	(18,959,288)	(264,673,776)	(13,002,711)

Exhibit 2, Tab 3, Schedule 1, Table 1: Depreciation Expense Reconciliation 2006 – 2011:

DEPRECIATION EXPENSE RECONCILIATION							
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Additions to Accumulated Depreciation	13,941,728	14,819,037	15,802,569	16,522,311	17,516,581	18,634,288	12,612,711
Less: Fully Allocated Depreciation							
Transportation Equipment	(516,208)	(604,317)	(510,443)	(472,752)	(529,301)	(704,519)	(917,569)
Stores Equipment	(26,296)	(26,262)	(21,967)	(16,339)	(16,339)	(16,339)	(16,339)
Tools, Shop, and Garage Equipment	(125,281)	(142,144)	(158,494)	(151,698)	(146,381)	(159,804)	(167,201)
Power Operated Equipment	(9,024)	(4,656)	(4,486)	(4,486)	(4,486)	(4,486)	(4,486)
	(676,809)	(777,379)	(695,390)	(645,275)	(696,507)	(885,148)	(1,105,595)
Add/(Subtract) Other Amortization							
Removal Costs	42,379	43,495	81,492	80,009	169,012	1,182,000	1,002,000
Amortization of PCB	-	-	-	117,163	461,896	482,000	-
Depreciation Adjustments	22,307	20,472	(16,807)	-	(78)	-	-
Amortization of Deferred Charges	-	1,172,836	426,480	142,160	-	-	-
	64,686	1,236,803	491,166	339,333	630,831	1,664,000	1,002,000
Net Depreciation	13,329,605	15,278,462	15,598,345	16,216,369	17,450,905	19,413,139	12,509,116
Depreciation per Trial Balance	13,329,605	15,278,462	15,598,345	16,216,369	17,450,905	19,413,140	12,509,117
Difference	0	- 0	0	- 0	- 0	- 0	- 0
Depreciation per audited financial statements	13,310,805	15,158,075	15,616,288	16,315,727	17,447,046		
Gain/Loss on Disposals	18,800	120,387	(17,943)	(99,358)	3,859		
	13,329,605	15,278,462	15,598,345	16,216,369	17,450,905		
Difference	0	(0)	(0)	0	0		

Exhibit 2, Tab 3, Schedule 2, Table 2: Variance Threshold Exceeded 2006 – 2011

OEB #	Description	2006	2007	2008	2009	2010	2011
1805	Land	-	-	-	-	-	-
1806	Land Rights	58,458	19,170	7,069	23,226	383,000	192,000
1808	Buildings and Fixtures	1,123,351	1,630,659	1,283,556	602,472	435,898	970,650
1815	Transformer Station Equipment - Normally Primary above 50 kV	3,474	12,600	3,803,296	257,953	814,102	1,643,000
1820	Distribution Station Equipment - Normally Primary below 50 kV	639,781	192,033	169,870	279,295	1,222,000	913,000
1830	Poles, Towers and Fixtures	5,802,455	5,777,486	4,388,180	7,129,091	7,455,828	5,268,405
1835	Overhead Conductors and Devices	2,191,510	1,983,311	2,073,555	2,214,142	1,988,000	924,000
1840	Underground Conduit	2,284,568	2,102,665	1,926,785	4,665,139	3,441,345	3,509,502
1845	Underground Conductors and Devices	6,352,682	23,445,365	16,144,870	7,731,744	11,303,857	13,350,056
1850	Line Transformers	3,160,025	2,278,674	5,378,129	6,208,233	4,860,014	6,123,387
1855	Services	714,723	793,538	544,543	613,536	661,552	767,000
1860	Meters	1,170,387	6,157,185	6,392,693	9,445,080	1,026,750	991,000
1908	Buildings and Fixtures	-	-	-	-	-	-
1915	Office Furniture and Equipment	47,337	86,526	84,367	2,570	528,000	168,475
1920	Computer Equipment - Hardware	453,294	476,458	155,453	70,653	840,400	305,200
1925	Computer Software	226,383	508,907	184,032	(0)	-	-
1930	Transportation Equipment	714,607	1,355,127	90,483	215,003	1,980,000	2,294,478
1935	Stores Equipment	19,150	0	-	-	-	-
1940	Tools, Shop and Garage Equipment	152,979	287,536	156,761	159,036	381,000	104,962
1950	Power Operated Equipment	-	0	-	-	-	-
1955	Communication Equipment	50,146	102,028	78,757	117,318	41,600	133,400
1960	Miscellaneous Equipment	16,025	15,620	12,711	8,554	-	-
1980	System Supervisory Equipment	195,795	208,555	144,806	64,979	101,000	501,000
1995	Contributions and Grants - Credit	(4,471,257)	(18,528,211)	(16,082,800)	(12,704,438)	(11,627,427)	(14,598,572)
2055	Construction Work in Progress--Electric	682,425	1,964,208	(1,397,746)	798,274	-	-
2040	Electric Plant Held for Future Use	-	-	3,554,454	258,332	-	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	5,118,257	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	84,843	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	(130,042)	5,268,063	-
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	61,000	961,600	554,800
	Total	**21,588,299**	**30,869,441**	**29,093,824**	**33,294,250**	**32,066,582**	**24,115,743**

Energy Probe Interrogatory # 8

Ref: Exhibit 2, Tab 2, Schedule 1.2

For each of the components under Account 1610 shown in Table 1 and 2, please identify the CCA class that is applicable.

Response:

The CCA classes that are applicable for the components under Account 1610 in Table 1 and 2 are as follows:

- Miscellaneous Intangible Plant – TS: – Class 47
- Miscellaneous Intangible Plant – Class 12

Energy Probe Interrogatory # 9

Ref: Exhibit 2, Tab 2, Schedule 4.0

Is there any impact on the calculation of rate base in 2010 and 2011 of the movement of assets to miscellaneous intangible plant in 2009? If yes, please quantify the impact on the 2010 and 2011 rate base and explain the impact.

Response:

There is no impact on the calculation of rate base in 2010 and 2011.

Energy Probe Interrogatory # 10

Ref: Exhibit 2, Tab 4, Schedule 2.0

a) Please confirm that the cost of power of $0.0694 per kWh referenced is based on the May 1, 2010 to April 30, 2011 period, based on the Regulated Price Plan as issued by the OEB on April 15, 2010.

Response:

Hydro One Brampton confirms that the cost of power of $0.0694 per kWh is based on the OEB Regulated Price Plan Price Report May 1, 2010 to April 30, 2011

b) Please provide the breakdown in 2009 between RPP and non-RPP volumes. Does HOBNI have any forecast for the 2011 test year that would indicate any change in this ratio between RPP and non-RPP volumes? If yes, please provide the forecast.

Response:

In 2009 the breakdown in 2009 between RPP and non-RPP volumes was 35.0% and 65.0% respectively. HOBNI does not have any forecast for the 2011 test year that would indicate any change in this ratio between RPP and non-RPP volumes

c) Please calculate the cost of power by applying the $0.0694 per kWh price to RPP volumes and the HOEP price of $0.03666 per kWh plus the Global Adjustment of $0.02772 per kWh as shown in the April 15, 2010 RPP report to the non-RPP volumes.

Response:

By applying the $0.0694 per kWh price to RPP volumes and the HOEP price of $0.03666 per kWh plus the Global Adjustment of $0.02772 per kWh as shown in the April 15, 2010 RPP report to the non-RPP volumes would be $257,805,304. However, the “Adjustment to Address Bias Towards Unfavorable Variance” of $0.001, and the “Adjustment to Clear Existing Variance” of $0.00114 has not been factored into this recalculated cost of power.

Energy Probe Interrogatory # 11

Ref: Exhibit 2, Tab 5, Schedule 1.0

a) When was the capital expenditure forecast for 2010 and 2011 prepared and finalized?

Response:

The capital expenditure forecast was prepared starting in March 2010 and finalized on June 9, 2010 when it was approved by the Board of Directors.

b) Does HOBNI have any more recent capital expenditure forecasts or projections based on activity to date in 2010 and projections for the remainder of the year? If yes, please provide the 2010 projects in the same level of detail as shown in Table 1.

Response:

There has been no material change in the projection for 2010.

c) How do any variances in the current 2010 projections from forecast impact on the forecasted capital expenditures for 2011?

Response:

There is no impact. Please see response to #11 b)

Energy Probe Interrogatory # 12

Ref: Exhibit 2, Tab 5, Schedules 3.0, 4.0, 5.0, 6.0, 7.0, 8.0

a) Please explain the low amount of construction work in progress forecast for 2010 and 2011 relative the actual construction work in progress shown for 2006, 2007, 2008 and 2009.

Response:

The construction work in progress forecast for 2010 and 2011 are listed in the Pro-Forma Financial Statements in Exhibit 1 Tab 3 Schedule 6.1 page 4 and Schedule 6.2 page 4 respectively. The amounts are:

Year	Change	Cumulative
2009	798,274.00	798,274.00
2010	3,216,066.00	4,014,340.00
2011	- 1,261,441.00	2,752,899.00

b) Are all of the capital expenditures shown in Schedule 7.0 for 2010 on schedule for completion before the end of year, with the exception of the $31,066 shown? If not, please update this schedule to reflect any change in the level of capital expenditures and the expected level of construction work in progress at the end of 2010.

Response:

Yes, capital expenditures are on schedule.

Energy Probe Interrogatory # 13

Ref: Exhibit 2, Tab 5, Schedules 2.0, 3.0, 4.0, 5.0

The evidence indicates the HOBNI typically recovers 50% of the labour and equipment costs with the City of Brampton and Region of Peel road widening projects. The evidence also indicates that the cost sharing with the Ministry of Transportation is governed by the MTO Corridor Control and Permit procedures manual.

a) Please explain why there were no contributions and grants recorded associated with the road widening capital costs of $4,810,184 in 2005.

Response:

Prior to 2009 all contributions and grants were netted against capital for road widening projects, rather than being booked into the 1995 GL. The balance of $4,810,184 represents the actual road widening spent by HOBNI net of any contributions and grants for 2005.

b) Please explain why there were no contributions and grants recorded associated with the road widening capital cost of $2,816,334 in 2006.

Response:

Prior to 2009 all contributions and grants were netted against capital for road widening projects, rather than being booked into the 1995 GL. The balance of $2,816,334 represents the actual road widening spent by HOBNI net of any contributions and grants for 2006.

c) Please explain why there were no contributions and grants recorded associated with the road widening capital cost of $2,735,883 in 2007.

Response:

Prior to 2009 all contributions and grants were netted against capital for road widening projects, rather than being booked into the 1995 GL. The balance of $2,735,883 represents the actual road widening spent by HOBNI net of any contributions and grants for 2007.

d) Please explain why there were no contributions and grants recorded associated with the road widening capital cost of $3,269,001 in 2008**.**

Response:

Prior to 2009 all contributions and grants were netted against capital for road widening projects, rather than being booked into the 1995 GL. The balance of $3,269,001 represents the actual road widening spent by HOBNI net of any contributions and grants for 2008.

Energy Probe Interrogatory # 14

Ref: Exhibit 2, Tab 5, Schedule 7.0, page 8

a) Please clarify what HOBNI means by the rework associated with the 4,500 sq ft that is not being utilized "will hinge on when/if the new tenant is found". Does HOBNI mean that it will not spend the $304,643 included in the 2010 capital budget if a tenant is not found?

Reponse:

This space requires substantial rework and therefore we would not spend monies until a tenant was secured or alternately we needed this space ourselves.

b) Please provide an update on the status of the search for a new tenant.

Reponse:

Still no tenant found.

c) Will HOBNI proceed with the $60,000 expenditure to reconfigure the old day-care parking area and remove the existing playground areas in 2010 if no replacement tenant is found? If yes, please explain why.

Response:

No

d) What was the annual revenue received for the rental of this space?

Response:

The annual revenue received for the rental of this space was as follows:

Year	Daycare rental revenue	
2009	$	33,963
2008	$	42,750
2007	$	42,375
2006	$	41,344

Energy Probe Interrogatory # 15

Ref: Exhibit 2, Tab 5, Schedules 7.0 & 8.0

With respect to the road widening expenditures in 2010 and 2011, HOBNI indicates that the information presented is based on preliminary information from the road authorities.

Does HOBNI have any more recent information from the road authorities? If yes, please provide the details and the impact on the capital expenditures forecast for 2010 and 2011.

Response:

Information from the Road authorities remains preliminary. Project confirmation will follow final Budget approval from City council, typically in February / March.

Energy Probe Interrogatory # 16

Ref: Exhibit 2, Tab 5, Schedules 7.0 & 8.0

HOBNI appears to propose that all of the 2010 and 2011 costs which are to be incurred to make eligible investments for the purpose of enabling the connection of renewable energy generation facilities to the distribution system be recovered from HOBNI's ratepayers. In other words, HOBNI appears to assume that the direct benefits that accrue to the HOBNI customers are equal to or higher than the eligible investment costs. However, HOBNI does not appear to have provided any calculation to support this.

The Board issued the EB-2009-0349 Report of the Board - Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09 on June 10, 2010.

a) Did HOBNI review the Report of the Board before filing the current application?

Response:

Yes

b) Please provide an estimate of the direct benefits based on the June 2010 Report of the Board.

Response:

Please refer to response for OEB Question 34

c) Please provide an estimate of the eligible investment costs that HOBNI is seeking to be determined by the Board.

Response:

Please refer to response for OEB Question 34.

d) If the direct benefits are less than the eligible investment costs, would HOBNI consider reducing its revenue requirement by the difference (i.e. the rate protection to be provided)? If not, why not?

Response:

Yes

e) If the Board determines that HOBNI should do the above calculations and some rate protection is required for the ratepayers of HOBNI, would HOBNI request the establishment of a variance account, as contemplated in the Report of the Board?

Response:

Yes.

f) Please provide a table as illustrated on page 17 (and discussed on pages 16 and 17) of the March 25, 2010 EB-2009-0397 Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence.

Response:

Please refer to response for OEB Question 34 when reviewing the following tables.

OM&A Expenditures	2010	2011	2012	2013	2014	2015
Gross Cost	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
Less Generator Contributions	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
Less Provincial Recovery	$0	$0	$0	$0	$0	$0
Net Distributor Costs	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

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Capital Expenditures	2010	2011	2012	2013	2014	2015
Gross Cost	**$1,033,000**	**$1,050,000**	**$1,072,000**	**$1,092,000**	**$1,113,000**	**$1,136,000**
Less Generator Contributions	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Less Provincial Recovery	**$666,500**	**$462,500**	**$471,750**	**$481,000**	**$490,250**	**$500,000**
Net Distributor Costs	**$366,500**	**$587,500**	**$600,250**	**$611,000**	**$622,750**	**$636,000**

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Energy Probe Interrogatory # 17

Ref: Exhibit 2, Tab 5, Schedule 8.0 &

Exhibit B, Tab 6, Schedule 1.1, Appendix E

With regard to the fleet maintenance capital expenditures for 2011 please provide the following:

a) A reconciliation, by vehicle number, of the vehicles scheduled to be replaced in 2011 as described on pages 18 and 19 of Exhibit 2, Tab 5, Schedule 8.0 with the fleet replacement schedule shown in Appendix E to Exhibit 2, Tab 6, Schedule 1.1. In particular, please provide an explanation for the following:

Response:

Per Exhibit 2 Tab 5 Schedule 8.0			Per Exhibit 2 Tab 6 Schedule 1.1 Appendix E		
Vehicle #	In Service Date	2011	Vehicle #	In Service Date	2011
9	1999	33,638	5	1999	27,000
25	1900	296,012	25	1993	517,700
45	1999	120,135	26	2006	588,640
49	2001	139,356	32	2000	423,200
72	1996	291,206	33	2000	423,200
76	1992	432,484	45	1999	135,200
79	1993	633,349	60	1999	54,080
101	1986	21,144	73	1996	423,200
163	1981	10,572	79	1993	588,640
171	1981	10,572	88	1997	423,000
174	1982	53,820	112	1192	22,000
179	1992	77,963	116	1998	12,000
new		12,013	163	1981	11,000
Fleet Improvements		35,996	174	1982	52,000
			179	1992	82,000
		2,168,259			3,782,860

i) any vehicles shown in the replacement schedule for replacement after 2011, but included in the 2011 capital budget (for example vehicles 9, 49 & 171);

Response:

Vehicle# 9 was assessed as requiring major maintenance and repairs thus the decision was made to replace Vehicle# 9 and delay the replacement of Vehicle #5.

V26 was completely rebuild and was in better condition than V49. The decision was made to replace V49 earlier and delay the replacement of V26

During regular maintenance it was discovered that V171 had structural damage. The decision was made to replace this vehicle sooner.

ii) any vehicles shown in the replacement schedule for replacement in 2011, but not included in the 2011 capital budget;

Response:

The Fleet Replacement Schedule is in line with our capital budget of $2,168,000

iii) any vehicles included in the 2011 capital budget, but not included in the replacement schedule for replacement (for example vehicle 76).

Response:

With the exception of V76, all the vehicles listed in our Fleet Replacement Schedule are in our capital budget. V76 replaced V73 in our capital budget, please see response to Energy Probe Question 7 regarding V76.

b) Please provide a table for each vehicle that is being replaced in 2011 showing the vehicle number and the market value (from Appendix E of Exhibit 2, Tab 6, Schedule 1.1). Please indicate why some of the vehicles to be replaced in 2011 do not appear to be listed in the table showing the market values. Please also indicate what the remaining net book value is for each of the vehicles to be replaced. How has HOBNI accounted for any market value (or resale value) in excess of net book value?

Response:

Vehicle #	Market Value	Net book value
9	1,100	1,038
25	14,000	-
45	9,000	3,500
49	65,000	51,744
72	9,000	10,306
76		-
79	30,000	-
101	2,600	6,661
163	900	-
171	900	-
174		-
179	6,000	-
	138,500	73,250

V76 is the only vehicle that is not listed in the market value tables. Please see response for Energy Probe Question 7 regarding V76

The vehicles that do not appear on the Fleet Market Value Table are Pole trailers and Cable pullers, these were not included in the Fleet Assessment.

Please see response to Energy Probe Question 29c for HOBNI treatment of any market value (or resale value) in excess of net book value.

c) The evidence indicates that for vehicle #72 the chassis was purchased in 2010 but the bin body and aerial device will be purchased in 2011. Is the capital expenditure forecast to be incurred in 2010 for the chassis included in the opening rate base for 2011? If yes, please explain how the vehicle can be in service without the bin body and aerial device being purchased and installed at the end of 2010. Please also provide the capital expenditure forecast for 2010 and the forecast for 2011 associated with this vehicle.

Response:

The capital expenditure is as follows:

2010- $137,198

2011- $291,206

Total $428,404

The total $428,404 will go into service once completed in 2011.

d) For vehicle #49, please explain if the purchase of the chassis means that the vehicle will be in service at the end of 2011 even though the remainder of the project will not be completed until 2012.

Response:

The chassis will be purchased in 2011 and Vehicle #49 will go into service once completed in 2012

e) For each vehicle replacement and addition noted in Exhibit B, Tab 5, Schedule 8.0, please provide the forecast cost, which add up to $2,168,000 in aggregate.

Response:

Please refer to table included in response to Part a of this question

Energy Probe Interrogatory # 18

Ref: Exhibit 3, Tab 2, Schedule 1.0, Table 3 &

Exhibit 3, Tab 1, Schedule 1.1, Table 1

a. Please explain why the revenues for the residential class is forecast to decline in 2011 as compared to 2010 at existing rates by about 4.0% despite a 1.0% increase in the number of customers and a 0.8% increase in the billed energy.

Response:

Revenue for the residential class is forecast to decline in 2011 as compared to 2010 at existing rates as a result of the Smart Meter Rider being included to calculate the 2010 fixed revenues but not the 2011 fixed revenues using existing rates.

b. Please explain why the revenues for the GS < 50 kW class is forecast to increase by only 0.4% in 2011 as compared to 2010 at existing rates despite a 2.1% increase in the number of customers and a 1.8% increase in billed energy.

Response:

The revenue for the GS < 50 kW class is forecast to increase in 2011 by only 0.4% as compared to 2010 at existing rates as a result of the Smart Meter Rider being included to calculate the 2010 fixed revenues but not the 2011 fixed revenues using existing rates.

c. If the responses to (a) and/or (b) are related to the smart meter rate rider, please provide the revenue forecast for 2010 and 2011 excluding the impact of the rate rider.

Response:

OPERATING REVENUE TABLE

Table 1: Operating Revenue Throughput Analysis (Excluding Smart Meter Impact)

Description	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test Year At Existing Rates	2011 Test Year At Proposed Rates
Distribution Revenue:								
Residential	28,804,232	30,564,062	31,832,733	32,348,857	32,878,324	32,320,633	32,611,130	33,913,877
General Service < 50 kW	6,753,149	6,923,804	7,212,603	7,049,604	7,040,316	6,952,680	7,083,429	6,609,534
General Service > 50 kW	8,234,737	8,716,748	8,915,309	9,017,460	9,095,685	8,780,215	8,955,510	10,658,221
Intermediate	9,443,369	10,229,132	10,036,833	9,530,709	9,020,912	8,755,570	8,812,785	8,814,322
Large Use (> 5000 kW)	1,494,553	1,978,745	2,176,019	2,458,555	2,421,532	2,269,735	2,364,211	2,134,272
Street Lighting	132,445	158,530	171,740	179,273	183,904	187,121	195,409	1,883,527
Unmetered Scattered Load	0	114,457	109,696	108,956	108,693	104,345	102,209	127,659
Sub-Total	**54,862,485**	**58,685,478**	**60,454,933**	**60,693,414**	**60,749,367**	**59,370,298**	**60,124,683**	**64,141,412**
Low Voltage Adder to Rates	**(94,500)**	**(65,797)**	**(67,103)**	**(68,221)**	**(67,065)**	**(65,742)**	**(67,464)**	**0**
Gross Distribution Revenue From Rates Charged	**54,767,985**	**58,619,681**	**60,387,831**	**60,625,193**	**60,682,302**	**59,304,556**	**60,057,219**	**64,141,412**
Other Revenue:								
SSS Administration Revenue	247,340	280,415	311,193	314,944	309,221	312,834	316,281	316,281
Retail Services Revenue	240,751	260,051	293,177	305,716	285,754	350,000	310,000	310,000
Service Transaction Requests (STR) Revenues	1,433	12,485	20,825	13,850	4,200	25,000	5,000	5,000
Rent From Electric Property	205,775	752,415	733,319	575,118	557,520	540,030	498,000	498,000
Late Payment Charges	866,886	1,090,020	1,220,696	1,219,746	1,314,408	1,310,000	1,450,331	1,450,331
Miscellaneous Service Revenue	842,243	1,348,713	1,458,177	1,299,510	1,107,039	1,188,970	1,152,000	1,152,000
Miscellaneous Non-Operating Income	451,223	824,249	52,357	10,106	184,973	150,000	252,000	252,000
Interest Income	152,787	524,343	481,318	322,429	26,803	6,680	2,799	2,799
Sub-Total	**3,008,438**	**5,092,690**	**4,571,062**	**4,061,417**	**3,789,918**	**3,883,514**	**3,986,412**	**3,986,412**
Gross Revenues Before Transformer Credit	**57,776,423**	**63,712,371**	**64,958,893**	**64,686,610**	**64,472,220**	**63,188,071**	**64,043,630**	**68,127,824**
Payments to Hydro One For LV Charges	**94,500**	**65,797**	**67,103**	**68,221**	**67,065**	**65,742**	**67,464**	**0**
Less: Transformer Credits	**(1,468,274)**	**(1,561,629)**	**(1,581,138)**	**(1,576,798)**	**(1,497,160)**	**(1,463,795)**	**(1,504,282)**	**(1,573,908)**
Total Operating Revenue	**56,402,648**	**62,216,538**	**63,444,857**	**63,178,033**	**63,042,125**	**61,790,018**	**62,606,813**	**66,553,916**

* Historical actual normalized throughput quantities and actual customer/connection counts for year multiplied by rates in effect for respective rate year.

Income Statement Amounts								
Service Revenue	53,299,711	57,058,052	58,806,693	59,048,394	59,185,142	57,840,762	58,552,937	62,567,504
Other Revenue	3,008,438	5,092,690	4,571,062	4,061,417	3,789,918	3,883,514	3,986,412	3,986,412
	56,308,148	**62,150,742**	**63,377,755**	**63,109,812**	**62,975,060**	**61,724,276**	**62,539,349**	**66,553,916**

d. Were the residential and/or GS < 50 kW distribution rates charged in January, 2010 through April, 2010 higher or lower than the rates that became effective May 1, 2010?

Response:

The residential and GS < 50 kW rates charged in January 2010 through April 2010 were higher than the rates that became effective May 1, 2010.

e. How many months of actual consumption is included in the 2010 purchases and billed kWh forecasts?

Response:

The forecast includes actual monthly consumption for each rate class from January 2003 through December 2009 which represents 84 months of data.

f. How many MicroFit customers does HOBNI expect to have connected to its system in 2011? How many current MicroFit customers does HOBNI have?

Response:

HOBNI expects to connect 60 – 70 microfit customers in 2011.

As of September 17, 2010 HOBNI has connected ten (10) microFIT customers.

Energy Probe Interrogatory # 19

Ref: Exhibit 3, Tab 2, Schedule 2.0

a) Please provide the forecast GDP growth rates for 2010 and 2011 used by HOBNI as published by the Ministry of Finance. Please also provide the estimated 2009 growth rate.

Response:

The GDP growth rates used by Hydro One Brampton were 2.7% for 2010 and 3.2% for 2011. The growth rate for 2009, as calculated as the actual change in GDP from 2008 to 2009 was 0.98%.

b) What is the date of the forecast from the Ministry of Finance used by HOBNI?

Response:

This forecast was published by the Ministry of Finance on March 25, 2010.

c) Has the Ministry of Finance published any more recent forecasts for GDP growth in 2010 and 2011 and the estimated growth for 2009? If yes, please provide these forecasts and indicate the impact on the forecast that the more recent forecast would have.

Response:

The Ministry of Finance has not published an update to the GDP growth rates.

d) Please provide a table showing the most recent publically available GDP forecasts for Ontario for 2010 and 2011 and estimated 2009 growth from the major Canadian financial institutions (available at the following addresses) and indicate the date of each forecast in the table:

http://www.td.com/economics/forecasts.jsp

http://www.bmonesbittburns.com/economics/welcome/publications.asp

http://www.rbc.com/economics/microec.html

http://www.scotiabank.com/cda/content/0,1608,CID8339_LIDen,00.html

http://research.cibcwm.com/res/Eco/EcoResearch.html

Please also include the calculation of the growth rates for 2009, 2010 and 2011 based on the average of the five forecasts noted.

Response:

Ontario GDP Forecast Growth Rates			
	2009	2010	2011
BMO	-2.50	3.00	2.50
CIBC	-3.10	3.70	2.40
RBC	-3.20	3.50	3.20
SCOTIA	-3.10	3.60	2.40
TD	-2.90	4.00	2.30
AVERAGE	-2.96	3.56	2.56

e) What is the impact on the forecast if the average growth rate for 2009 through 2011 calculated above in part (d) was used in the forecast equation in place of the Ministry of Finance forecasted used by HOBNI?

Response:

	2010 Original	2010 GDP Revised	Variance	2011 Original	2011 GDP Revised	Variance
Predicted kWh Purchases	3,821,797,458	3,842,755,617	0.55%	3,898,527,442	3,922,094,179	0.60%
Billed kWh Purchases	3,698,071,300	3,718,350,964	0.55%	3,772,317,241	3,795,121,034	0.60%
Residential	1,099,386,751	1,102,086,622	0.25%	1,107,769,581	1,110,853,385	0.28%
GS < 50 kW	285,620,803	286,081,696	0.16%	290,725,436	291,259,984	0.18%
USL	5,013,040	5,059,449	0.93%	4,899,876	4,949,236	1.01%
GS > 50 kW (kWh)	1,097,553,564	1,102,374,595	0.44%	1,123,789,074	1,129,318,968	0.49%
GS > 50 kW (kW)	3,008,017	3,021,230	.44%	3,079,920	3,095,075	0.49%
Intermediate (kWh)	816,592,994	823,849,522	0.89%	832,077,628	840,141,373	0.97%
Intermediate (kW)	1,844,198	1,860,586	0.89%	1,879,169	1,897,380	0.97%
Large Use (kWh)	365,387,029	370,456,334	1.39%	383,275,616	388,908,918	1.47%
Large Use (kW)	664,899	674,123	1.39%	697,451	707,702	1.47%
SLR (kWh)	28,517,120	28,442,746	-0.26%	29,780,031	29,689,168	-0.31%
SLR (kW)	84,878	84,656	-0.26%	88,637	88,366	-0.31%
Total kWh	3,698,071,300	3,718,350,964	0.55%	3,772,317,241	3,795,121,034	0.60%
Total kW	5,601,992	5,640,596	0.69%	5,862,912	5,788,523	-1.27%

Energy Probe Interrogatory # 20

Ref: Exhibit 3, Tab 2, Schedule 3.0

a) Please confirm that the t-statistic on the population coefficient of 0.62 indicates that the coefficient is not statistically significant at a 60% level of confidence**.**

Response:

Yes a t-statistic of 0.62 indicates that the coefficient is not statistically significant at a 60% confidence level However, the low t-statistic value could be attributed to correlation with other model variables. Population was retained in the model because of its theoretical importance. Clearly, demand for electricity increases as population grows

b) Did HOBNI try a regression equation using the number of customers (not connections) in place of the population variable? If yes, please provide the regression results in the same format as shown in Table 1 of Exhibit 3, Tab 2, Schedule 3.1. If not, please estimate the equation using the number of customers in place of the population variable and provide the regression results.

Response:

Yes. Using customers in place of population in the regression model yields the following results

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Blackout Flag	Customers	Number of Peak Hours	Predicted Purchases	Variances (kWh)	% Variance
Jan-03	307,542,957	814.6	0.0	100.73%	31	0	0	97,867	352	315,076,979	7,534,022	2.45%
Feb-03	279,902,418	699.0	0.0	101.92%	28	0	0	98,141	320	284,885,217	4,982,799	1.78%
Mar-03	292,786,171	581.1	0.0	102.61%	31	1	0	98,701	336	296,552,451	3,766,280	1.29%
Apr-03	269,814,265	372.5	2.4	101.84%	30	1	0	99,179	336	276,272,367	6,458,103	2.39%
May-03	267,913,712	177.8	0.0	101.52%	31	1	0	99,661	336	271,924,681	4,010,969	1.50%
Jun-03	286,282,449	43.4	52.9	100.93%	30	0	0	100,151	336	290,290,941	4,008,491	1.40%
Jul-03	318,440,802	0.2	118.3	99.01%	31	0	0	100,917	352	321,706,853	3,266,051	1.03%
Aug-03	297,771,903	2.0	128.0	100.28%	31	0	1	101,336	320	297,771,903	0	0.00%
Sep-03	267,335,938	54.9	24.0	102.42%	30	1	0	102,323	336	271,854,393	4,518,456	1.69%
Oct-03	274,153,307	275.8	0.0	101.55%	31	1	0	103,247	352	279,226,161	5,072,854	1.85%
Nov-03	281,313,885	398.5	0.0	102.57%	30	1	0	103,901	320	276,383,519	(4,930,366)	-1.75%
Dec-03	295,245,545	561.5	0.0	100.45%	31	0	0	103,901	336	298,330,617	3,085,072	1.04%
Jan-04	318,825,772	849.1	0.0	100.73%	31	0	0	104,266	336	314,037,140	(4,788,632)	-1.50%
Feb-04	292,561,276	631.7	0.0	101.93%	29	0	0	105,148	320	288,909,502	(3,651,774)	-1.25%
Mar-04	304,403,356	487.3	0.0	102.62%	31	1	0	105,552	368	296,123,865	(8,279,491)	-2.72%
Apr-04	280,729,504	331.5	0.0	103.71%	30	1	0	105,997	336	279,285,987	(1,443,516)	-0.51%
May-04	284,754,157	158.9	8.6	103.38%	31	1	0	106,343	320	278,738,469	(6,015,689)	-2.11%
Jun-04	296,130,055	44.2	31.6	102.77%	30	0	0	107,072	352	289,045,614	(7,084,441)	-2.39%
Jul-04	316,526,152	3.6	85.4	103.20%	31	0	0	107,574	336	318,841,865	2,315,713	0.73%
Aug-04	311,532,144	12.8	59.6	104.53%	31	0	0	108,356	336	312,083,052	550,907	0.18%
Sep-04	300,510,639	30.0	41.2	106.75%	30	1	0	109,289	336	293,594,600	(6,916,039)	-2.30%
Oct-04	288,181,524	226.3	1.5	105.36%	31	1	0	109,910	320	285,788,248	(2,393,277)	-0.83%
Nov-04	296,760,230	380.3	0.0	106.42%	30	1	0	110,860	352	293,583,316	(3,176,914)	-1.07%
Dec-04	315,819,546	643.4	0.0	104.22%	31	0	0	111,499	336	315,521,225	(298,321)	-0.09%
Jan-05	329,967,591	770.0	0.0	104.73%	31	0	0	111,883	320	321,383,639	(8,583,952)	-2.60%
Feb-05	293,588,958	616.4	0.0	105.97%	28	0	0	112,296	320	294,213,516	624,558	0.21%
Mar-05	313,508,514	608.6	0.0	106.69%	31	1	0	112,604	352	314,034,725	526,211	0.17%
Apr-05	285,449,756	306.8	0.0	106.72%	30	1	0	113,046	336	288,364,018	2,914,262	1.02%
May-05	287,810,113	189.4	0.8	106.39%	31	1	0	113,433	336	289,403,872	1,593,760	0.55%
Jun-05	354,566,496	8.9	146.3	105.76%	30	0	0	113,902	352	350,509,154	(4,057,342)	-1.14%
Jul-05	365,920,796	0.0	188.7	105.42%	31	0	0	114,401	320	371,478,950	5,558,154	1.52%
Aug-05	358,835,199	0.2	140.7	106.77%	31	0	0	114,864	352	358,927,809	92,610	0.03%
Sep-05	314,383,694	22.6	50.6	109.05%	30	1	0	115,627	336	305,348,294	(9,035,400)	-2.87%
Oct-05	304,341,532	220.2	8.0	108.14%	31	1	0	116,144	320	297,998,556	(6,342,976)	-2.08%
Nov-05	311,009,155	388.4	0.0	109.22%	30	1	0	116,886	352	303,629,967	(7,379,188)	-2.37%
Dec-05	329,446,542	665.3	0.0	106.97%	31	0	0	117,251	320	323,682,723	(5,763,820)	-1.75%

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Blackout Flag	Customers	Number of Peak Hours	Predicted Purchases	Variances (kWh)	% Variance
Jan-06	329,248,077	551.8	0.0	107.97%	31	0	0	117,810	336	323,842,630	(5,405,446)	-1.64%
Feb-06	304,825,405	604.2	0.0	109.26%	28	0	0	118,059	320	304,963,438	138,033	0.05%
Mar-06	325,241,932	516.6	0.0	109.99%	31	1	0	118,436	368	323,177,525	(2,064,406)	-0.63%
Apr-06	289,070,045	293.3	0.0	109.98%	30	1	0	118,719	304	294,169,436	5,099,391	1.76%
May-06	310,032,606	136.9	26.0	109.64%	31	1	0	119,036	352	312,036,388	2,003,782	0.65%
Jun-06	333,895,801	19.5	72.6	109.00%	30	0	0	119,223	352	328,211,329	(5,684,473)	-1.70%
Jul-06	371,225,703	0.0	167.3	107.81%	31	0	0	119,511	320	369,829,484	(1,396,219)	-0.38%
Aug-06	353,706,210	4.2	101.5	109.20%	31	0	0	119,954	352	349,368,815	(4,337,395)	-1.23%
Sep-06	298,103,405	80.9	12.9	111.52%	30	1	0	120,373	320	297,066,392	(1,037,013)	-0.35%
Oct-06	307,942,171	288.3	1.1	110.46%	31	1	0	121,120	336	308,681,688	739,517	0.24%
Nov-06	312,999,806	382.0	0.0	111.56%	30	1	0	121,303	352	311,405,759	(1,594,047)	-0.51%
Dec-06	317,982,954	500.5	0.0	109.26%	31	0	0	121,502	304	320,784,964	2,802,011	0.88%
Jan-07	332,533,628	649.6	0.0	110.25%	31	0	0	121,978	352	339,140,479	6,606,851	1.99%
Feb-07	318,174,492	740.1	0.0	111.56%	28	0	0	122,265	320	319,903,496	1,729,003	0.54%
Mar-07	330,329,411	546.7	0.0	112.32%	31	1	0	122,531	352	330,360,757	31,346	0.01%
Apr-07	301,193,988	356.4	0.0	112.73%	30	1	0	122,826	320	309,375,009	8,181,021	2.72%
May-07	313,881,665	136.4	22.4	112.38%	31	1	0	123,243	352	319,881,343	5,999,678	1.91%
Jun-07	352,305,947	16.5	99.2	111.72%	30	0	0	123,602	336	347,413,498	(4,892,450)	-1.39%
Jul-07	350,987,926	3.2	106.1	110.77%	31	0	0	124,162	336	354,389,935	3,402,009	0.97%
Aug-07	363,680,291	5.2	141.0	112.19%	31	0	0	124,789	352	378,076,168	14,395,877	3.96%
Sep-07	320,412,436	36.7	47.5	114.58%	30	1	0	125,182	304	319,023,361	(1,389,074)	-0.43%
Oct-07	318,245,128	137.6	19.8	112.66%	31	1	0	125,923	352	319,557,769	1,312,640	0.41%
Nov-07	323,515,779	462.5	0.0	113.78%	30	1	0	126,666	352	323,112,887	(402,892)	-0.12%
Dec-07	333,331,077	630.7	0.0	111.43%	31	0	0	127,278	304	334,844,636	1,513,560	0.45%
Jan-08	344,575,662	626.0	0.0	110.91%	31	0	0	127,771	352	339,915,959	(4,659,703)	-1.35%
Feb-08	326,113,372	674.7	0.0	112.23%	29	0	0	128,195	320	326,471,329	357,958	0.11%
Mar-08	331,077,485	610.2	0.0	112.99%	31	1	0	128,469	304	328,421,160	(2,656,325)	-0.80%
Apr-08	303,230,329	253.9	0.0	112.66%	30	1	0	128,795	352	308,264,573	5,034,244	1.66%
May-08	301,056,523	193.5	2.5	112.30%	31	1	0	129,119	336	310,541,685	9,485,161	3.15%
Jun-08	334,428,490	22.7	71.5	111.65%	30	0	0	129,253	336	334,283,629	(144,861)	-0.04%
Jul-08	363,118,367	1.0	111.0	110.46%	31	0	0	129,572	352	357,487,684	(5,630,682)	-1.55%
Aug-08	341,326,026	12.7	64.0	111.88%	31	0	0	129,740	320	336,627,279	(4,698,747)	-1.38%
Sep-08	317,499,538	59.5	26.7	114.26%	30	1	0	129,916	336	313,933,809	(3,565,729)	-1.12%
Oct-08	310,230,042	278.6	0.0	110.62%	31	1	0	130,305	352	310,026,379	(203,663)	-0.07%
Nov-08	313,840,850	451.6	0.0	111.72%	30	1	0	130,617	304	307,702,811	(6,138,039)	-1.96%
Dec-08	328,946,880	654.6	0.0	109.42%	31	0	0	130,791	336	333,412,306	4,465,426	1.36%
Jan-09	340,125,286	830.2	0.0	108.49%	31	0	0	130,978	336	339,079,863	(1,045,424)	-0.31%
Feb-09	298,423,228	606.4	0.0	109.78%	28	0	0	131,032	304	303,694,435	5,271,207	1.77%
Mar-09	317,878,968	515.6	0.0	110.52%	31	1	0	131,149	352	321,774,017	3,895,048	1.23%
Apr-09	288,048,157	295.9	1.2	109.12%	30	1	0	131,194	320	293,331,016	5,282,860	1.83%
May-09	279,549,261	158.8	6.9	108.77%	31	1	0	131,294	320	295,619,167	16,069,906	5.75%
Jun-09	301,280,403	49.3	34.2	108.14%	30	0	0	131,379	352	308,109,543	6,829,140	2.27%
Jul-09	312,634,481	6.2	43.7	107.09%	31	0	0	131,547	352	314,451,057	1,816,576	0.58%
Aug-09	342,969,587	9.8	91.0	108.47%	31	0	0	131,699	320	336,604,028	(6,365,559)	-1.86%
Sep-09	305,441,230	55.2	20.9	110.78%	30	1	0	131,774	336	298,426,630	(7,014,601)	-2.30%
Oct-09	307,520,270	287.8	0.0	108.83%	31	1	0	131,942	336	301,592,179	(5,928,091)	-1.93%
Nov-09	303,012,736	361.2	0.0	109.92%	30	1	0	132,069	320	298,923,983	(4,088,753)	-1.35%
Dec-09	331,058,361	631.3	0.0	107.65%	31	0	0	132,245	352	328,201,574	(2,856,787)	-0.86%

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Blackout Flag	Customers	Number of Peak Hours	Predicted Purchases	Variances (kWh)	% Variance
Jan-10		726.4	0.0	107.89%	31	0	0	132,391	320	329,111,378	329,111,378	
Feb-10		639.6	0.0	108.13%	28	0	0	132,507	304	299,378,732	299,378,732	
Mar-10		559.5	0.0	108.37%	31	1	0	132,628	368	318,613,953	318,613,953	
Apr-10		331.8	1.3	108.61%	30	1	0	132,749	320	293,300,631	293,300,631	
May-10		165.2	12.0	108.85%	31	1	0	132,871	320	298,457,433	298,457,433	
Jun-10		41.7	55.5	109.09%	30	0	0	132,992	352	320,873,487	320,873,487	
Jul-10		5.5	109.4	109.34%	31	0	0	133,113	336	350,290,264	350,290,264	
Aug-10		11.9	89.9	109.58%	31	0	0	133,235	336	342,464,624	342,464,624	
Sep-10		81.2	28.2	109.82%	30	1	0	133,357	336	299,619,968	299,619,968	
Oct-10		265.0	2.1	110.07%	31	1	0	133,478	320	303,334,316	303,334,316	
Nov-10		426.3	0.0	110.31%	30	1	0	133,600	336	305,964,428	305,964,428	
Dec-10		620.9	0.0	110.56%	31	0	0	133,722	368	340,384,463	340,384,463	
Jan-11		726.4	0.0	110.85%	31	0	0	133,845	320	339,609,541	339,609,541	
Feb-11		639.6	0.0	111.14%	28	0	0	133,967	304	310,061,117	310,061,117	
Mar-11		559.5	0.0	111.43%	31	1	0	134,089	368	329,481,712	329,481,712	
Apr-11		331.8	1.3	111.72%	30	1	0	134,212	304	301,951,590	301,951,590	
May-11		165.2	12.0	112.02%	31	1	0	134,335	336	312,101,464	312,101,464	
Jun-11		41.7	55.5	112.31%	30	0	0	134,457	352	332,302,400	332,302,400	
Jul-11		5.5	109.4	112.61%	31	0	0	134,580	320	359,504,904	359,504,904	
Aug-11		11.9	89.9	112.90%	31	0	0	134,703	352	356,674,874	356,674,874	
Sep-11		81.2	28.2	113.20%	30	1	0	134,826	336	311,617,645	311,617,645	
Oct-11		265.0	2.1	113.50%	31	1	0	134,950	336	317,926,297	317,926,297	
Nov-11		426.3	0.0	113.80%	30	1	0	135,073	352	320,748,561	320,748,561	
Dec-11		620.9	0.0	114.09%	31	0	0	135,197	336	348,152,574	348,152,574	
		Weather Normalized										

	Actual	Predicted	Variance (kWh)	Variace %
2003	3,438,503,351	3,480,276,082	41,772,731	1.21%
2004	3,606,734,355	3,565,552,882	(41,181,473)	-1.14%
2005	3,848,828,345	3,818,975,222	(29,853,123)	-0.78%
2006	3,854,274,114	3,843,537,848	(10,736,266)	-0.28%
2007	3,958,591,768	3,995,079,337	36,487,570	0.92%
2008	3,915,443,564	3,907,088,603	(8,354,961)	-0.21%
2009	3,727,941,968	3,739,807,491	11,865,523	0.32%
2010		**3,801,793,675**		
2011		**3,940,132,679**		

Total to 2009	26,350,317,465	26,350,317,465	0

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SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.976870924
R Square	0.954276803
Adjusted R Square	0.949399662
Standard Error	5404392.962
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	8	4.57186E+16	5.71482E+15	195.6631548	5.09482E-47
Residual	75	2.19056E+15	2.92075E+13		
Total	83	4.79092E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-379067929.9	38432655.26	-9.863173058	3.45622E-15	-455629704.1	-302506155.7	-455629704.1	-302506155.7
Heating Degree Days	51190.03777	3918.095572	13.0650304	5.1825E-21	43384.79126	58995.28428	43384.79126	58995.28428
Cooling Degree Days	462163.9224	25671.99553	18.00264891	6.04351E-29	411022.6856	513305.1593	411022.6856	513305.1593
Ontario Real GDP Monthly %	358194298	33666667.7	10.63943427	1.22028E-16	291126857.7	425261738.2	291126857.7	425261738.2
Number of Days in Month	7912745.769	826329.2981	9.575777825	1.20476E-14	6266613.42	9558878.119	6266613.42	9558878.119
Spring Fall Flag	-10868902.17	1855124.634	-5.858852809	1.16301E-07	-14564499.89	-7173304.449	-14564499.89	-7173304.449
Blackout Flag	-28228977.07	5796956.521	-4.869620286	6.05406E-06	-39777106.47	-16680847.68	-39777106.47	-16680847.68
Customers	-66.59050001	122.4908648	-0.543636459	0.588304014	-310.604812	177.423812	-310.604812	177.423812
Number of Peak Hours	150188.192	39470.92293	3.805033702	0.000287301	71558.08261	228818.3014	71558.08261	228818.3014

c) If the equation requested in (b) above results in an equation that has a statistically significant coefficient for the customer variable (at an 80% confidence level) and the proper sign, please provide the 2011 predicted kWh purchases.

Response:

As the coefficient for customers is negative in this regression, the 2011 predicted kWh purchases have not been included.

Energy Probe Interrogatory # 21

Ref: Exhibit 3, Tab 2, Schedules 1.0, 2.0 & 3.0

a) It is not clear how HOBNI has forecast heating and cooling degree days for 2010 and 2011. At page 3 of Exhibit 3, Tab 2, Schedule 2.0, HOBNI indicates that a 30 year average is calculated for both heating and cooling degree days with these averages applied in the bridge and test years. However, at page 5 of Exhibit 3, Tab 2, Schedule 3.0, the evidence states that the weather normalized forecast quantities for the bridge and test years use the average monthly heating and cooling degree days which have occurred from January 2003 to December 2009, a period of only 7 years. Please clarify which average of heating and cooling degree days has been used in the forecast for 2010 and 2011**.**

Response:

In order to forecast heating and cooling degree days for 2010 and 2011 HOBNI has used a 30 year historical average. The wording on page 5 of Exhibit 3, Tab 2, Schedule 3.0 is incorrect. “has occurred from January 2003 to December 2009” should read “has occurred from January 1980 to December 2009”

b) HOBNI references the Toronto Hydro forecasting methodology on page 1 of Exhibit 3, Tab 2, Schedule 1.0. How many years did Toronto Hydro use in the calculation of the average heating and cooling degree days used in their multifactor regression model? If the average is different from the average used by HOBNI (as clarified above in part (a)), please provide the 2011 test year predicted kWh purchases using the same length of time as used by Toronto Hydro for heating and cooling degree days.

Response:

Toronto Hydro used a 10 average for heating and cooling degree days where as Hydro One Brampton has used a 30 year average. The 2011 predicted kWh purchases are 3,915,093,435 when a 10 year heating and cooling degree day average is used.

Energy Probe Interrogatory # 22

Ref: Exhibit 3, Tab 2, Schedules 1.0, 2.0 & 3.0

a) Tables 4 and 5 of Schedule 3.0 do not appear to match the customer figures shown in Tables 2 and 3 of Schedule 1.0. Please provide corrected tables to whichever tables need correction**.**

Response:

Hydro One Brampton assumes that Energy Probe intended to request that tables 5 and 6 of schedule 3 be restated as the USL GS < 50 labels were inverted. As such please find corrected tables 5 and 6 included bellow (as opposed to tables 4 and 5)

Table 5: Historical Customer/Connection Data

	Residential	GS < 50	USL	GS > 50	Intermediate	Large Use	SL
2003	91,671	6,512	1,105	1,357	126	4	2
2004	98,355	6,648	1,130	1,393	124	3	2
2005	104,822	6,892	1,159	1,364	121	3	2
2006	109,778	7,075	1,207	1,402	119	4	2
2007	114,119	7,294	1,250	1,417	117	5	2
2008	119,060	7,437	1,267	1,491	116	6	2
2009	121,041	7,529	1,280	1,554	117	6	2

Table 6: Exponentially Smoothed Customer/Connection Data

	Residential	GS < 50	USL	GS > 50	Intermediate
2003	91,178	6,504	1,352	1,105	125
2004	97,502	6,621	1,395	1,127	126
2005	104,150	6,868	1,365	1,156	121
2006	109,292	7,055	1,397	1,201	119
2007	113,492	7,262	1,413	1,245	117
2008	118,639	7,430	1,482	1,265	115
2009	120,998	7,530	1,549	1,278	114

b) Please confirm that the exponential smoothing methodology used results in the exponentially smoothed number of residential customers being less than the actual number of customers in year over the entire period, by an average of more than 500 customers. Please explain how this methodology provides an accurate estimate for 2010 and 2011 when it under forecast in each historical year.

Response:

While it is true that the exponential smoothing method refers to smoothed historical numbers that are less than actual historical results, it is not true that exponential smoothing under forecasts historical customer numbers. Exponential smoothing, as utilized by Hydro One Brampton within their 2011 Rate Application, takes smoothed historical numbers to calculate an average growth rate to apply to 2010 and 2011. The smoothed numbers themselves are not meant to represent a forecast and should not be interpreted as such. Hydro One Brampton has chosen to use exponential smoothing to

forecast 2010 and 2011 customer numbers as this methodology yields an average growth rate that is cognizant of the declining customer growth rates present within Brampton. Exponential smoothing works like a simple weighted average except that it places exponentially decreasing weights on historical data. This allows Hydro One Brampton to effectively forecast their customer base for 2010 and 2011 while considering the historically high customer growth rates, but paying more mind to the more recent declining growth rates.

c) Please confirm that the exponential method under forecast the column labeled USL in 6 out of the 7 historical years.

Response:

See Part B

d) Please confirm that the exponential method under forecast the GS >50 (or GS < 50) class in all but one of the historical years.

Response:

See Part B

e) Is HOBNI aware of any LDC having used, and the Board having approved, the exponential smoothing methodology to forecast customers? If so, please provide references. In particular, did any of the distributors noted on page 1 of Exhibit 3, Tab 2, Schedule 1.0 use the exponential smoothing methodology?

Response:

Hydro One Brampton is not aware of any other LDC having used the exponential smoothing methodology.

f) Please provide a revised forecast of customers in Table 8 using the geometric mean growth rate used by Burlington Hydro in EB-2009-0259 based on the actual historical number of customers shown in Table 5 in place of the exponential smoothing methodology.

Response:

Table 8: Customer/Connection Forecast

	Residential	USL	GS < 50	GS > 50	Intermediate	Large Use	SLR
HOBNI Geomean Growth Rate	4.74%	2.48%	2.64%	2.26%	-1.65%	-	-
2010 Forecast	126,778	1,312	7,728	1,589	112	6	2
2011 Forecast	132,787	1,344	7,932	1,625	110	6	2

g) What is the impact on the revenue deficiency shown in Revenue Requirement Work Form in Exhibit 1, Tab 2, Schedule 3.1 (page 8 of 10) if the customer forecast was modified as requested in part (f) above and the remainder of the forecast methodology remained as proposed by HOBNI

Response:

Since revenue deficiency is calculated independent of volumes there would be no impact on the revenue deficiency component of the revenue requirement work form given a change in the forecast number of customers.

h) Please reconcile the forecast addition of 1,336 residential customers in 2010 and the addition of 1,283 residential customers in 2011 with the 2010 projection of 4,000 low density residential lots in 2010 (Exhibit 2, Tab 5, Schedule 7.0) and the connection of an additional 4,500 low density residential services in 2011 (Exhibit 2, Tab 5, Schedule 8.0).

Response:

Please note that on Exhibit 2, Tab 5, Schedule 7.0 and Exhibit 2, Tab 5, Schedule 8.0 refer to residential lots or units. The residential unit projections in 2010 (4,000) and 2011 (4,500), are estimated based on City draft Plan application submissions from various subdivisions within the City of Brampton. HOBNI has an obligation to ensure that there are connection facilities available to connect all City planned connections. Historically, the number of new housing units identified in the City's draft does not materialize fully. As mentioned above, these forecasts are for residential lots. They may or may not have a residential dwelling on it during the service year. A serviced lot does not, or may not have a residential unit constructed on it and thus, the lot does not equate to a customer. HOBNI's forecast of 1,336 and 1,283 for 2010 and 2011 respectively are based on trending methodology that utilizes actual historical customer connections.

i) Is the data shown in Table 5 the number of customers at the end of each year or the average number of customers for each year?

Response:

The data provided in Table 5 represents the average number of customers per year.

j) Please provide the actual number of customers for each rate class based on the most recent month available for 2010**.**

Response:

Period	August 2010
Residential	123,306
GS < 50 kW	7,795
USL	61
Street Lights	2
GS > 50 < 700	1,540
GS > 700 < 5000	115
GS > 5000	6
Total Customers	132,825

Hydro One Brampton would additionally like to clarify that the USL class in the forecast represents the number of connections, not the number of customers. While the USL class is billed on a per customer basis, usage varies on a per connection basis which is why that measurement was chosen as the preferred variable. The data provided in the table above is the number of customers for the USL class as that is the information that is stored and readily available at this date.

Energy Probe Interrogatory # 23

Ref: Exhibit 3, Tab 2, Schedule 3.0

a) Please confirm that the average use figures shown in Table 9 are actual use per customer and not normalized use per customer figures.

Response:

The averages provided in Exhibit 3, Tab 2, Schedule 3.0, Table 9: Historical Annual Usage per Customer was calculated using historical data, not normalized data.

b) Please confirm that the geometric mean shown in Table 10 is independent of the figures for 2004 through 2008 and can be calculated directly from the 2003 and 2009 values alone. If this cannot be confirmed, please explain why not.

Response:

The Geometric Means presented in Table 10 are in fact the geometric means and cannot be calculated using the 2003 and 2009 values alone. A Geometric mean is a type of average that indicates the central tendency or typical value in a set of numbers. To calculate the Geometric Mean all numbers are multiplied and the *n*th root (n being the number of values in the set) of the resulting product is taken. This methodology is independent of simply looking at the growth rate between the first and last year of historical data.

c) Does HOBNI agree that the geometric mean shown in Table 10 is determined by the 2003 and 2009 values and that these values reflect the actual heating and cooling degree days in those years?

Response:

The Geometric Mean data presented in Table 10 was calculated using actual historical data from 2003 through 2009. The average use per customer was determined by dividing total consumption by the average number of customers on a per class basis. The growth rate (or decline rate) in average use per customer was calculated for the years 2004 through 2009 and then the geometric mean of those growth rates (or decline rates) rates were calculated. These values reflect actual heating and cooling degree days in those years in so far as these values were calculated based on actual historical data.

d) Please confirm the following figures. If they cannot be confirmed, please provide the correct figures**.**

	2003	2009
Heating Degree Days	**3,981.3**	**3,807.7**
Cooling Degree Days	**325.6**	**197.9**

Response:

The figures presented above should be presented as follows:

	2003	2009
HDD	3,981.50	3,835.80
CDD	325.60	197.90

e) Please confirm that if the 2009 actual consumption were adjusted or "normalized" to reflect the 2003 heating and cooling degree days, the 2009 kWh purchases would be 61,847,062 kWh higher based on the coefficients estimated in the equation shown in Table 1. The calculation of this figure is shown below:

(2003 HDD - 2009 HDD) x 49,250.1 + (2003 CDD - 2009 CDD) x 417,362.92 = (3,981.3 - 3,807.7) x 49,250.1 + (325.6 - 197.9) x 417,362.92 = 173.6 x 49,250.1 + 127.7 x 417,362.92 = 61,847,062.

If the degree days shown in the table in part (d) above are not correct, please replace them in the above formula and calculate the change in the kWh for 2009 based on 2003 heating degree days.

Response:

The formula in question is corrected as follows:

(2003 HDD - 2009 HDD) x 49,250.1 + (2003 CDD - 2009 CDD) x 417,362.92 = (3,981.5 - 3,835.7) x 49,250.1 + (325.6 - 197.9) x 417,362.92 = 173.6 x 49,250.1 + 127.7 x 417,362.92 = 7,180,664+53,297,244= 60,477,908

It is not true that normalizing the heating and cooling degree days for 2009 by utilizing the 2003 values would increase the 2009 purchases by 60,477,908 kWh. The coefficients presented in the above equation were taken from a regression that used the 2009 heating and cooling degree days to determine the prediction equation. Substituting in the 2003 values to the equation that was determined using historical actual data is not an accurate calculation of the impact of using 2003 values in place of 2009 values.

f) Please add the figure from part (e) above to the actual 2009 kWh purchases and use the HOBNI methodology to allocate the increase to each of the rate classes and provide the resulting average use per customer for 2009 for each rate class that reflects the same heating and cooling degree days as those recorded in 2003.

Response:

Through adding the 60,477,908 kWh (identified in the above formula in part G) to purchases for 2009 the average use per customer for each rate class is as follows:

Residential	GS<50	USL	GS>50	Intermediate	LU	SL
9,023	37,355	15,049	699,954	7,037,938	60,746,689	11,836,444

Energy Probe Interrogatory # 24

Ref: Exhibit 3, Tab 2, Schedule 2.0 &

Exhibit 3, Tab 2, Schedule 3.0 &

Exhibit 3, Tab 2, Schedule 1.0, Table 2

HOBNI states, at page 2 of Exhibit 3, Tab 2, Schedule 2.0, that it "has elected to use 2007 usage patterns to allocate this adjustment as the total predicted purchases for the 2011 Test Year most closely reflect total purchased kWh from 2007. This is again stated at page 11 of Exhibit 3, Tab 2, Schedule 3.0, although the comparison is now stated to be based on the retail kWh figures.

a) Please confirm that the total predicted kWh purchases for 2011 (3,898,527,442) is closer to the actual levels shown for 2005, 2006 and 2008 than for 2007.

Response:

It is true that the total predicted kWh purchases for 2011 are closer to 2005, 2006, and 2008 values than to 2007. Hydro One Brampton would however like to clarify that the 2011 purchases below are inclusive of the 64,010,000 kWh reduction associated with 2011 provincial targeted CDM impacts. The second table below provides the variances when using the 2011 purchases before the 2011 CDM impact

2011 Impacted by CDM:

2011	2005	Variance from 2011	2006	Variance from 2011	2007	Variance from 2011	2008	Variance from 2011
3,898,527,442	3,848,828,345	1.29%	3,833,699,383	1.69%	3,988,592,061	-2.26%	3,915,428,135	0.43%

2011 Not Impacted by CDM:

2011	2005	Variance from 2011	2006	Variance from 2011	2007	Variance from 2011	2008	Variance from 2011
3,962,537,442	3,848,828,345	2.87%	3,833,699,383	3.25%	3,988,592,061	-0.66%	3,915,428,135	1.19%

Hydro One Brampton believes it is more accurate to compare the 2011 values prior to the impact of CDM. The adjustment for CDM relates to future mandated CDM values by the OPA. These programs were not in effect in 2007 and as such, to determine which year to align the class kWh allocation to, comparison should be made prior to that adjustment.

b) Please confirm that the closest actual level to that forecast for kWh purchases for 2011 occurred in 2008.

Response"

Yes the closest actual kWh purchases to the 2011 forecast is the year 2008, however, the closest kWh purchases to the 2011 forecast prior to the adjustment for OPA CDM programs is 2007.

c) Please confirm that the total billed kWh forecast for 2011 (3,772,317,241) is closer to the actual levels shown for 2005, 2006 and 2008 than for 2007.

Response:

It is true that the total predicted billed kWh for 2011 are closer to 2005, 2006, and 2008 values than to 2007. Hydro One Brampton would however like to clarify that the 2011 purchases below are after a reduction of 64,010,000 kWh for CDM impacts. The second table below provides the variances when using the 2011 purchases before the CDM impact.

2011 Impacted by CDM:

2011	2005	Variance from 2011	2006	Variance from 2011	2007	Variance from 2011	2008	Variance from 2011
3,772,317,241	3,723,506,554	1.31%	3,718,723,113	1.44%	3,839,000,000	-1.74%	3,791,763,566	0.51%

2011 Not Impacted by CDM:

2011	2005	Variance from 2011	2006	Variance from 2011	2007	Variance from 2011	2008	Variance from 2011
3,834,254,994	3,723,506,554	2.89%	3,718,723,113	3.01%	3,839,000,000	-0.12%	3,791,763,566	1.11%

Hydro One Brampton believes it is more accurate to compare the 2011 values prior to the impact of CDM. The adjustment for CDM relates to future mandated CDM values by the OPA. These programs were not in effect in 2007 and as such, to determine which year to align the class kWh allocation to, comparison should be made prior to that adjustment.

d) Please confirm that the closest actual level to that forecast for billed kWh for 2001 occurred in 2008.

Response:

Yes the closest actual billed kWh to the 2011 forecast is the year 2008, however, the closest billed kWh to the 2011 forecast prior to the adjustment for OPA CDM programs is 2007.

e) Please provide the figures in Table 14 if the adjustments are based on using the 2008 actual data in place of the 2007 data (for 2011 only).

Response:

	Residential	USL	GS < 50	GS > 50	Intermediate	Large Use	SL	Total
Unadjusted Forecast								
2011	1,072,768,740	4,339,638	284,658,377	1,061,025,381	740,555,007	319,338,254	30,811,309	3,513,496,706
Consumption Adjustment								
2011	29,192,324	-4,772,980	743,238	80,197,948	41,556,912	112,369,229	-466,135	258,820,535
Adjusted Forecast								
2011	1,101,961,064	5,082,875	279,885,397	1,141,223,328	782,111,918	431,707,483	30,345,174	3,772,241

f) Please provide the figures in Table 14 if the adjustments are based on using the 2009 actual data in place of the 2007 data (for 2011 only).

Response:

	Residential	USL	GS < 50	GS > 50	Intermediate	Large Use	SL	Total
Unadjusted Forecast								
2011	1,072,768,740	4,339,638	284,658,377	1,061,025,381	740,555,007	319,338,254	30,811,309	3,513,496,706
Consumption Adjustment								
2011	19,239,514	6,274,813	656,927	89,384,250	55,925,728	86,770,271	569,033	258,820,535
Adjusted Forecast								
2011	1,092,008,254	4,996,565	290,933,190	1,150,409,631	796,480,735	406,108,525	31,380,342	3,772,241

g) Please show all the calculations and assumptions used to create the consumption adjustment weighting factors shown in Table 13.

Response:

The adjustment weighting factors were calculated using the following formula

$$\frac{-(total\ sensitivity\ factors * total\ unadjusted\ kWh) \times (class\ unadjusted\ kWh - 2011\ target\ kWh)}{(class\ unadjusted\ kWh - difference\ between\ billed\ forecast\ kWh\ and\ unadjusted\ customer\ forecast\ kWh)}$$

Target 2011 kWh were calculated based on the 2007 ratios of each class to total kW

h) Please show the calculations that result in the consumption adjustments (for 2011 only) for each rate class shown in Table 14.

Response:

The calculations used to determine the consumption adjustment for 2011 are presented on the following 2 pages. The first page illustrates the values used and the second page illustrates the formulas.

Customer Class Average Consumption Forecast										Total
	2010	**3,559,417,348**	1,080,927,480	282,469,635	4,695,742	1,064,591,727	766,979,427	330,727,715	29,025,622	**3,559,417,348**
	2011	**3,513,496,706**	1,072,768,740	284,658,377	4,339,638	1,061,025,381	740,555,007	319,338,254	30,811,309	**3,513,496,706**
Adjusted Consumption Forecast										**Total**
	2010	**3,698,071,300**	1,099,386,751	285,620,803	5,013,040	1,097,553,564	816,592,994	365,387,029	28,517,120	**3,698,071,300**
	2011	**3,772,317,241**	1,107,769,581	290,725,436	4,899,876	1,123,789,074	832,077,628	383,275,616	29,780,031	**3,772,317,241**
Sensitivity Factors			**726.5962**	**474.6517**	**2875.0103**	**1317.3570**	**2752.2753**	**4458.8670**	**-745.3949**	**Total**
	2010	**138,653,953**	785,397,795,218	134,074,679,368	13,500,305,143	1,402,447,330,462	2,110,938,571,004	1,474,670,900,854	-21,635,552,084	**5,899,394,029,966**
	2011	**258,820,535**	779,469,685,387	135,113,569,793	12,476,504,791	1,397,749,179,603	2,038,211,289,948	1,423,886,810,330	-22,966,593,863	**5,763,940,445,989**
Allocation of Consumption Adjustment										**Total**
	2010	**138,653,953**	18,459,270	3,151,168	317,299	32,961,837	49,613,566	34,659,314	-508,502	**138,653,953**
	2011	**258,820,535**	35,000,841	6,067,059	560,238	62,763,693	91,522,621	63,937,362	-1,031,278	**258,820,535**

2007 Class Ratios of Total	28.7116%	7.7828%	0.1315%	28.9083%	24.5389%	9.2552%	0.6717%
2011 Billed kWh based on 2007 Ratios	1,083,093,149	293,591,907	4,959,614	1,090,514,492	925,685,136	349,134,652	25,338,291
Customer Migration from Intermediate to GS < 50				36,000,000	-36,000,000		
Adjust SL to 29,000,000 kWh		-3,689,500					3,689,500
To take 14,000,000 from Residential	14,000,000	-3,000,000		-6,000,000	-5,000,000		
Adjust LU to 715,000 KW					-45,000,000	45,000,000	
Target for 2011	1,097,093,149	286,902,407	4,959,614	1,120,514,492	839,685,136	394,134,652	29,027,791

1

Customer Class Average Consumption Forecast									Total
2010	=SUM(I38:O38)	=I23*'Rate Class Customer Model'!C14	=J23*'Rate Class Customer Model'!D14	=K23*'Rate Class Customer Model'!E14	=L23*'Rate Class Customer Model'!F14	=M23*'Rate Class Customer Model'!G14	=N23*'Rate Class Customer Model'!H14	=O23*'Rate Class Customer Model'!I14	=SUM(I38:O38)
2011	=SUM(I39:O39)	=I24*'Rate Class Customer Model'!C15	=J24*'Rate Class Customer Model'!D15	=K24*'Rate Class Customer Model'!E15	=L24*'Rate Class Customer Model'!F15	=M24*'Rate Class Customer Model'!G15	=N24*'Rate Class Customer Model'!H15	=O24*'Rate Class Customer Model'!I15	=SUM(I39:O39)

Adjusted Consumption Forecast									Total
2010	=H11	=I38+I50	=J38+J50	=K38+K50	=L38+L50	=M38+M50	=N38+N50	=O38+O50	=SUM(I42:O42)
2011	=H12	=I39+I51	=J39+J51	=K39+K51	=L39+L51	=M39+M51	=N39+N51	=O39+O51	=SUM(I43:O43)

Sensitivity Factors		=(-$P$47*(I39-I63)/(I39*$H$47))	=(-$P$47*(J39-J63)/(J39*$H$47))	=(-$P$47*(K39-K63)/(K39*$H$47))	=(-$P$47*(L39-L63)/(L39*$H$47))	=(-$P$47*(M39-M63)/(M39*$H$47))	=(-$P$47*(N39-N63)/(N39*$H$47))	=(-$P$47*(O39-O63)/(O39*$H$47))	Total
2010	=H42-H38	=I38*I45	=J38*J45	=K38*K45	=L38*L45	=M38*M45	=N38*N45	=O38*O45	=SUM(I46:O46)
2011	=H43-H39	=I39*I45	=J39*J45	=K39*K45	=L39*L45	=M39*M45	=N39*N45	=O39*O45	=SUM(I47:O47)

Allocation of Consumption Adjustment									Total
2010	=SUM(I50:O50)	=I46/$P$46*$H$46	=J46/$P$46*$H$46	=K46/$P$46*$H$46	=L46/$P$46*$H$46	=M46/$P$46*$H$46	=N46/$P$46*$H$46	=O46/$P$46*$H$46	=SUM(I50:O50)
2011	=SUM(I51,J51,K51,L51,M51,N51,O51)	=I47/$P$47*$H$47	=J47/$P$47*$H$47	=K47/$P$47*$H$47	=L47/$P$47*$H$47	=M47/$P$47*$H$47	=N47/$P$47*$H$47	=O47/$P$47*$H$47	=SUM(I51:O51)

2007 Class Ratios of Total	=I8/$H$8	=J8/$H$8	=K8/$H$8	=L8/$H$8	=M8/$H$8	=N8/$H$8	=O8/$H$8
2011 Billed kWh based on 2007 Ratios	=I54*$H$12	=J54*$H$12	=K54*$H$12	=L54*$H$12	=M54*$H$12	=N54*$H$12	=O54*$H$12
Customer Migration from Intermediate to GS < 50				36000000	=-36000000		
Adjust SL to 29,000,000 kWh		=-3689500					3689500
To take 14,000,000 from Residential	14000000	-3000000		-6000000	-5000000		
Adjust LU to 715,000 KW					-45000000	45000000	
Target for 2011	=SUM(I55:I62)	=SUM(J55:J62)	=SUM(K55:K62)	=SUM(L55:L62)	=SUM(M55:M62)	=SUM(N55:N62)	=SUM(O55:O62)

Energy Probe Interrogatory # 25

Ref: Exhibit 3, Tab 2, Schedule 2.0 &

Exhibit 3, Tab 2, Schedule 3.0

Please explain where in Schedule 3.0 the adjustment related to the CDM impact of 64 GWh is shown.

Response:

Hydro One Brampton included the impact of the 64 GWh by removing them from the 2011 purchases before the 2011 billed kWh were determined. As indicated in Exhibit 3, Tab 2, Schedule 3.1, Table 1, the model predicts 3,962,537,442 kWh for 2011. This value is reduced by 64,010,000 kWh to determine the 3,898,527,442 kWh presented in Exhibit 3, Tab 2, Schedule 3.0 Table 3.

Energy Probe Interrogatory # 26

Ref: Exhibit 3, Tab 2, Schedule 6.0

a) Please provide a table that shows the actual historical ratio of kW/kWh for 2003 through 2009 and the average for each of the 4 rate classes over this 7 year period.

Reponse:

	GS>50	Intermediate	Large Use	ST
kW/kWh				
2003	0.2738%	0.2315%	0.1885%	0.3057%
2004	0.2671%	0.2281%	0.1739%	0.2885%
2005	0.2679%	0.2272%	0.1694%	0.2991%
2006	0.2741%	0.2249%	0.1764%	0.2949%
2007	0.2739%	0.2236%	0.1801%	0.2962%
2008	0.2743%	0.2265%	0.1834%	0.2983%
2009	0.2821%	0.2334%	0.2034%	0.2996%
Average	0.2733%	0.2279%	0.1822%	0.2975%

b) Please provide the resulting kW forecast for 2011 as shown in Table 2, but using the averages calculated in part (a) above.

Response:

	GS > 50	Intermediate	Large Use	SLR
2011	3,071,351	1,896,247	698,259	88,582

c) What is the revenue impact (at current rates) of the response to part (b) above?

Response:

	GS > 50	Intermediate	Large Use	SLR
2011 Updated	8,800,962	8,757,052	2,269,815	187,121
2011 Original	8,955,510	8,812,785	2,364,211	195,409
Difference	(154,548)	(55,733)	(94,396)	(8,288)

d) Please explain what the reference to Table 3-19 in schedule 3 refers to.

Response:

This reference is an error. The correct reference is Table 2: Summary of Weather Normalized Load Forecast in schedule 1.

Energy Probe Interrogatory # 27

Ref: Exhibit 3, Tab 3, Schedule 2.0 &

Exhibit 1, Tab 1, Schedule 8.0

a) The evidence indicates in Exhibit 1 that HOBNI is considered a host distributor because it supplies a distribution substation in Hydro One Network Inc.'s service territory. Please explain where the revenue associated with this customer is shown in Schedule 2 of Exhibit 3, Tab 3. In particular, which rate class contains this customer?

Response:

The revenue associated with this customer is not shown in Schedule 2 of Exhibit 3, Tab 3. Due to the immaterial revenue amount related to this charge, Hydro One Brampton has not included this revenue in this schedule. In addition, Hydro One Brampton credits the amounts billed to this customer to USoA account 4075 - Billed LV, this is to the benefit of customers.

b) Why is there not a separate rate class for this customer?

Response:

In Hydro One Brampton's 2006 Cost of Service Application this customer service charge was established as Distribution Wheeling Service Rate. It was not ordered that this customer had to have its own separate rate class. Hydro One Brampton chose not to include this as a class for this filing, as indicated in Exhibit 7, Tab 1, Schedule 1.0:

"The revenues associated with this embedded distributor and the LV rate were approximately $2,200 for 2009. Over the past several years the load supplied to this distributor has been declining. In light of this, and its relatively low impact on revenues, Hydro One Brampton has opted not to include this as a class to be modeled in this cost allocation filing. Hydro One Brampton is proposing to maintain the current rate as an approved rate and will continue to credit this revenue to the LV variance account."

c) Please confirm that the transformer allowance cost for the GS > 50 kW and GS 700 to 4,999 kW classes are recovered only from customers in those rate classes.

Response:

The volumetric distribution charges for the GS > 50 kW and GS 700 to 4,999 kW classes include transformer costs associated with each specific class as though all customers use distribution transformation, then customers owning their own transformers receive a transformer ownership allowance.

Energy Probe Interrogatory # 28

Ref: Exhibit 3, Tab 4, Schedule 1.0

Please provide the most recent year-to-date actual revenues for 2010 in the same level of detail as shown in Table 1. Please provide the same year-to-date period revenues recorded in 2009**.**

Response:

The June year-to-date actual revenues for 2010 with the same year-to-date period revenues in 2009 are as follows:

Description	June 2010 YTD	June 2009 YTD
Other Distribution Revenue		
Specific Service Charges	594,722	492,219
Late Payment Charges	637,080	711,620
Other Distribution Revenue	395,342	455,962
Other Income and Expenses	141,306	103,151
Total	**1,768,449**	**1,762,952**

Energy Probe Interrogatory # 29

Ref: Exhibit 3, Tab 4, Schedule 1.1

a) Please explain the reduction of $40,000 in account 4082 in 2011 as compared to 2010.

Response:

HOBNI has reviewed account 4082. It would appear that the value in the 2010 Bridge year is overstated by approximately $50,000. Historically, the revenue from this account has typically been approximately $300,000. The revenue forecast for this account for the Test Year is $310,000.

b) Please explain the reduction of more than $40,000 in account 4210 in 2011 as compared to 2010. If this reduction is related to the reduction in rent related to the day-care rental, please indicate the lost revenue associated with this.

Response:

The reduction is related to the day-care tenant having vacated the premises ($34k) and less square footage being rented by Hydro One.

c) Please explain why there is no revenue shown in account 4355 for 2011 when there are a significant number of vehicles forecast to be replaced in 2011? What are the forecasted market values of the vehicles being replaced?

Response:

No revenue is shown due to the uncertain nature of the future market values at auction of the vehicles being replaced. The forecast assumes that the net gain or loss will be close to zero

d) Please explain the increase of more than $100,000 in account 4390 in 2011 as compared to 2010.

Response:

The increase is due to increased revenue from the sale of scrap metal. This is a function of anticipated higher maintenance activity and scrap metal prices.

e) Please provide the assumptions used for 2011 for the calculation of the interest and dividend income in account 4405. Please compare the interest rate forecast and the cash balance forecast for 2011 with the actual average values for 2009.

Response:

The cash balance for 2011 is assumed to fluctuate throughout the year, changing from a bank overdraft to a positive bank balance at the end of 2011.

f) Please explain why there have been no arrears certificates since 2006 (as shown in Table 2).

Response:

Arrears certificates were letters being requested from the Purchasers lawyer outlining any arrears that were outstanding on an account. HOBNI has not had a lawyer request this letter since October 2006.

g) Please explain why there is no revenue shown for 2011 for Miscellaneous Energy Charges (was Bell Co) shown in Table 2.

Response:

Hydro One Brampton's billing system was modified so that specific charges are used, as opposed to a miscellaneous category, so that the appropriate charge is shown on the customer's bill

Energy Probe Interrogatory # 30

Ref: Exhibit 4, Tab 1, Schedule 1.0 &

Exhibit 1, Tab 2, Schedule 2.0

a) Please provide a breakdown of the $3.6 million noted on line 27 of page 1 into each of its components: new Asset Management department, costs related to GEGEA, CDM costs, and inflationary impacts.

Response:

The $3.6M consists of $1.5M in planned staff additions, including a new Asset Management department, $0.3M in costs related to GEGEA , $0.6 M due to the effects of inflation and $0.9 due to increased line maintenance due to aging equipment.

b) Please provide a version of Table 1 that uses CGAAP for 2010 and 2011 rather than IFRS.

Response:

The following version of Table 1 uses CGAAP for 2010 and 2011 rather than IFRS:

	2006 Board Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	Bridge Year (BY) 2010	Test Year (TY) 2011
Operation	2,720,134	3,350,836	3,079,156	3,544,751	3,815,041	4,900,708	4,559,988
Maintenance	2,700,089	3,023,980	3,091,210	3,374,105	3,159,226	3,590,436	3,904,606
Billing and Collecting	3,512,796	3,775,564	3,820,263	4,324,468	4,897,921	4,632,782	5,656,663
Community Relations	256,376	1,018,450	797,999	371,587	363,138	570,000	640,000
Administrative and General	4,558,610	4,986,820	5,137,182	5,558,770	5,601,103	6,699,374	7,445,278
Total OM&A Expenses	13,748,005	16,155,651	15,925,811	17,173,680	17,836,429	20,393,300	22,206,535

Energy Probe Interrogatory # 31

Ref: Exhibit 4, Tab 1, Schedule 4.0

a) Please update Table 1 to show the most recent forecasts for 2010 and 2011 if more recent forecasts are available**.**

Response:

See table below for the current updated data available for the years.

	2010	2011	2012	2013	2014	2015
CPI – Ontario (%)	2.4	2.1	2.1	2.0	2.1	2.0
Dx cost escalation for Construction (%)	1.9	1.6	2.3	3.2	3.8	3.4
Dx cost escalation for Operations & Maintenance (%)	2.8	2.1	2.3	2.1	2.3	2.4
Exchange Rate (CDN$/US$)	1.030	1.021	1.050	1.067	1.086	1.124

CPI-Ontario was based on the IHS Global Insight July 2010 forecast and US cost escalators forecasts were based on the Global Insight February 2010 forecast.

The exchange rate forecasts for 2010, 2011, 2012 are based on the July 2010 Consensus Forecast while the 2013, 2014, 2015 exchange rate forecasts are based on the July 2010 Global Insight.

b) How much of the increase due to inflation is due to each of the inflation escalators shown in Table 1**.**

Response:

HOB does not have the detailed information from Global Insight to answer this question. Since electricity cost is a very small component in the CPI index, its share to the increase in inflation is expected to be small

.

Energy Probe Interrogatory # 32

Ref: Exhibit 4, Tab 2, Schedule 1.1

a) Please provide a complete Table 1 (the final column is missing on the current version).

Response:

The complete Table 1 from Exhibit 4, Tab 2, Schedule 1.1 has been included, but reflects the CGAAP numbers as per HOBNI's September 2, 2010 letter:

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year (BY) 2010	Variance BY 2010 - 2009 Actuals	Test Year (TY) 2011	Variance TY - BY
Operation	2,720,134	3,350,836	630,702	3,079,156	(271,680)	3,544,751	465,594	3,815,041	270,290	4,900,708	1,085,667	4,559,988	(340,720)
Maintenance	2,700,089	3,023,980	323,891	3,091,210	67,230	3,374,105	282,895	3,159,226	(214,879)	3,590,436	431,210	3,904,606	314,170
Billing and Collecting	3,512,796	3,775,564	262,768	3,820,263	44,699	4,324,468	504,205	4,897,921	573,454	4,632,782	(265,139)	5,656,663	1,023,881
Community Relations	256,376	1,018,450	762,075	797,999	(220,451)	371,587	(426,412)	363,138	(8,449)	570,000	206,862	640,000	70,000
Administrative and General	4,558,610	4,986,820	428,210	5,137,182	150,361	5,558,770	421,588	5,601,103	42,334	6,699,374	1,098,271	7,445,278	745,904
Total OM&A Expenses	13,748,005	16,155,651		15,925,811		17,173,680		17,836,429		20,393,300		22,206,535	
Variance from previous year			2,407,646		(229,840)		1,247,870		662,748		2,556,871		1,813,235
Percent change (year over year)			17.51%		-1.42%		7.84%		3.86%		14.34%		8.89%
Percent change: Test year vs Most Current Actuals		24.50%											
Average for 2006-2009		6.95%											
Compound Annual Growth Rate (for 2006 to 2009)		1.69%											

b) For each of the 5 OM&A cost categories shown in Table 1, please quantify the increase in 2010 over 2009 and the change in 2011 over 2010 that is directly associated with the change from CGAAP to IFRS in 2010.

Response:

Table 1 has been re-stated in CGAAP as an answer to Energy Probe Interrogatory # 30 b)

c) Please provide the most recent year-to-date costs incurred for 2010 in the same level of detail as shown in Table 1. Please also provide the same year-to-date costs incurred in 2009 for each category of costs. Please confirm that the year-to-date actuals are based on CGAAP for 2009 and IFRS for 2010. Please show separately the increase in the 2010 year-to-date figures that are attributable to the change to IFRS**.**

Response:

	June 2010 YTD	June 2009 YTD	Variance
Operation	1,978,360	2,067,262	(88,902)
Maintenance	1,490,423	1,659,456	(169,033)
Billing and Collecting	2,190,649	2,686,154	(495,505)
Community Relations	217,419	205,150	12,268
Administrative and General	3,886,661	2,947,717	938,945
Total OM&A Expenses	9,763,512	9,565,739	197,773

The June 2010 year-to-date actuals and the June 2009 year-to-date comparatives are both based on CGAAP

Energy Probe Interrogatory # 33

Ref: Exhibit 4, Tab 2, Schedule 1.2

a) Will any of the meter expense (account 5065) identified on page 7 be capitalized? If not, why not?

Response:

None of the meter expenses identified on page 7 will be capitalized. The costs associated with the older areas are due to removal costs, the software costs will not be eligible for capitalization as the program will be completed and cross phase testing is a maintenance activity.

b) Will any of the meter expense identified on page 7 be recovered through the smart meter account referenced on line 18 of Exhibit 6, Tab 1, Schedule 1.0, page 1?

Response:

No.

c) Please explain the difference between the $1,010,849 increase and the sum of the three components described, which total $820,000.

Response:

The remaining increase in costs of $190,000 is comprised of several other expenses. We expect an increase in our three phase reverification program of approximately 120,000 and an increase in Meter Service Provider costs of approximately $40,000. The remainder of the increase is due to small miscellaneous increases.

d) Please provide the most recent year-to-date bad debt expense in 2010 and the figure for the same period in 2009, excluding the portion of the auto sector ($233,000) one-time bankruptcies.

Response:

As of June 30, 2010, the year-to-date bad debt expense is $143,556 and the figure for the same period in 2009 excluding the auto sector bankruptcy of $233,000 is $371,124.

e) Is the increase of $221,000 in Hydro One Corporate charges on account of Finance charges related to IFRS implementation a onetime charge for 2010 or is it an on-going cost?

Response:

The $221,000 in Hydro One Corporate charges is not related to IFRS implementation. Please refer to Ontario Energy Board Interrogatory #23.

f) Please provide more explanation related to the increase in meter reading expense in 2011 as described on page 8. Is the $848,611, or some portion thereof, currently included in the smart meter variance account? Is this a one-time charge or will the meter reading expense remain at a level of more than $1 million per year after the 2011 test year?

Response:

Currently, all smart meter maintenance costs are being included in the smart meter variance account. Smart meter reading costs associated with the MDMR are a new cost that will remain at a high level until the end of 2013 at which time the SME (Smart Meter Entity) costs will have been recovered. The meter reading costs are estimated to be approximately $800,000 annually thereafter, not factoring in customer growth

Energy Probe Interrogatory # 34

Ref: Exhibit 4, Tab 2, Schedule 1.3, Table 1

a) What is the percentage increase in 2010 over 2009 after removing the disallowable costs in capital?

Response:

The percentage increase in 2010 over 2009 after removing the disallowable costs in capital is 14%.

b) What is the percentage increase in 2011 over 2010 if the disallowable costs in capital are removed from both years?

Response:

The percentage increase in 2011 over 2010 after removing the disallowable costs in capital is 9%.

c) Please explain why some of the differences shown by account in Table 1 do not match the differences in the figures provided in Table 1 of Exhibit 4, Tab 2, Schedule 1.2 (for example 5010 Load Dispatching).

Response:

The differences are due to the Wages and Benefits cost driver being itemized as a separate item.

Energy Probe Interrogatory # 35

Ref: Exhibit 4, Tab 2, Schedule 1.3, pages 10-12

a) For each of the positions noted under Wages and Benefits, please indicate whether the positions have been filled.

Response:

Assistant Supervisor – Customer Accounts: Not filled.

Customer Accounts Representative: Not filled.

Two Line Apprentice: One filled.

Outage Planning Coordinator: Not filled.

Software Developer: Filled.

b) Please disaggregate the $837,021 into each of the components listed in the explanation (prior year staff additions, retirements, promotions, resignations and terminations). For each of these categories, please explain if these are onetime costs or whether then are ongoing costs and please explain why.

Response:

The $837,021 comprises of the following:

Staff Additions - $444,942: Salaries due to new positions are ongoing costs.

Retirements - $67,557: Salaries for employees replacing vacant positions due to prior year retirements are ongoing costs.

Promotions - $317,772: Salaries for employees replacing vacant positions due to internal promotions are ongoing costs.

Resignations - $6,749: Salaries for employees replacing vacant positions due to resignations are ongoing costs.

c) Please provide the total postage and stationery cost for 2009 and the forecast cost for 2010 and 2011. Please explain the increase of $216,297 in terms of the increase in postage noted (5.56% and 3.92%) and the percentage growth in the number of customers in 2010 and 2011.

Response:

The total postage and stationery cost for 2009 is $1,069,831 and the forecast for 2010 and 2011 is $1,189,677 and $1,248,977 respectively. The increase of $216,297 included $86,568 in billing salaries that should have been excluded as it is already included in Wages and Benefits. Therefore, the revised cost driver for 2010 is $129,729 which is comparable to 2008 and 2009. The percentage growth in the number of customers for 2010 is 2.3% and for 2011 is 1.1%.

d) If the load dispatching costs for 2010 are comparable to the previous year, please explain the increase of more than $95,000.

Response:

Load dispatching costs has an increase due to the planned hiring of summer students, and anticipation of spend more hours on SCADA management.

e) Please explain the technology upgrades resulting in the increase in general administrative salaries and expenses. Does this increase include any increases related to salaries? If yes, is this not double counting the increase noted under wages and benefits?

Response:

This relates to Information Systems expenses which is included in USofA account 5615 General Administrative Salaries and Expenses. It does include $62,135 related to salaries for a forecasted Software Developer position that should have been excluded as it is already included under Wages and Benefits.

The technology upgrade is in part due to manufacturer warranty expiring and the requirement for hardware/software maintenance contracts for existing equipment. Also included is additional contract support for internet, security and programming services.

f) Please provide the most recent year-to-date collecting expense for 2010 and the corresponding figure for the same period in 2009. Please remove any expenses incurred in 2009 related to the bankruptcies of the large auto related accounts (if required).

Response:

The year-to-date collecting expense for June 2010 is $463,107 and the corresponding figure for the same period in 2009 is $405,458.

Energy Probe Interrogatory # 36

Ref: Exhibit 4, Tab 2, Schedule 1.3, pages 13-15

a) Please explain why the increase in wages and benefits of $205,135 in 2011 over 2010 is in addition to the $837,021 shown in 2010 as compared to 2009.

Response:

The increase in wages and benefits of $205,135 in 2011 over 2010 is in addition to the $837,021 shown in 2010 due to the hiring of new personnel during the year of 2010 and not at the beginning of the year.

b) Please provide all assumptions and calculations used to calculate the increase of $848,611 related to meter reading. Is HOBNI requesting any variance account related to the costs associated with MDR?

Response:

Please refer to the response to SEC's IR #19F for an explanation pertaining to the increase of $848,611. As stated in Exhibit 9 Tab 3 Schedule 1.1 Page 7 line 23 onward, Hydro One Brampton "is projecting annual ongoing costs of $758,949 commencing 2011. If Hydro One Brampton does not have these costs approved for inclusion in the proposed Revenue Requirement Hydro One Brampton request that these costs be deferred in the new deferral account proposed for Meter Data Management/Repository costs."

Energy Probe Interrogatory # 37

Ref: Exhibit 4, Tab 2, Schedule 3.0

a) What is the total cost associated with the current cost of service application? Are there any costs other than the intervener and legal costs shown in Table 6?

Response:

As per Exhibit 4 Tab 2 Schedule 1.3 Page 13 Lines 25-26 Intervener costs $50,000 and Legal costs $20,000. These costs are identified in Table 6.

b) Does HOBNI intend to amortize the one-time costs associated with the current cost of service application over two or more years? If not, why not?

Response:

HOBNI did not amortize the one-time costs associated with the current cost of service application over two or more years as it was deemed not to be material.

c) When does HOBNI expect to be back before the Board with its next cost of service application?

Response:

HOBNI expects to be back before the Board with its next cost of service application for rates effective for January 1, 2015

Energy Probe Interrogatory # 38

Ref: Exhibit 4, Tab 4, Schedule 9.0

a) Please provide a table that shows for each of Executive, Management and Non-Union, the total incentive compensation related cost for each of 2006 through 2009 and the forecast for 2010 and 2011.

Response:

Provided on Table in 4/4/9.1

b) For each year and for each employee group noted above in (a), please indicate the actual incentive cost represented as a percentage of the total incentive available. Please provide the forecasted percentages for each employee group for the 2010 bridge and 2011 test years.

Response:

The forecasted incentive for 2010 and 2011 is 66.7% of maximum for all management groups

c) Approximately what percentage of the scorecard results are based on shareholder value/benefits and what percentage of the results are based on ratepayer value/benefits?

Response:

The scorecard is not weighted for the various measures and is included in the Business Plan for each year.

Energy Probe Interrogatory # 39

Ref: Exhibit 4, Tab 5, Schedule 1.0

Are any of the fees paid to HOI related to HOI's Board of Directors? If yes, please indicate the amount included in the test year forecast.

Response:

The portion of 2011 corporate charges attributable to Hydro One Inc.'s Board is $14,714.

Energy Probe Interrogatory # 40

Ref: Exhibit 4, Tab 6, Schedule 1.2

a) How does HOBNI account for the revenue from the sales of scrap metal? Is the revenue used to offset OM&A costs, or are these revenues recorded in one the accounts shown in Exhibit 3, Tab 4, Schedule 1.1, Table 1. If so, please explain which account this revenue is recorded in.

Response:

The revenue from the sales of scrap metal is recorded in the USoA account 4390 shown in Exhibit 3, Tab 4, Schedule 1.1, Table 1.

b) What is the forecast for the sale of scrap metal in 2010 and 2011 and where is the impact on the test year revenue requirement shown in the evidence?

Response:

The forecast for the sale of scrap metal in 2010 and 2011 is $125,000 and $250,000, respectively. USoA 4390 is included in total Other Operating Revenue which is deducted from the test year revenue requirement.

Energy Probe Interrogatory # 41

Ref: Exhibit 4, Tab 7, Schedule 1.2

a) The opening balance shown for 2007 and 2008 is equal to the opening balance for the previous year, plus the additions for that the previous year. However, the opening balance for 2009 is $468,980,295, which is more than the opening balance for 2008 ($435,851,987) plus the 2008 additions of $28,073,070. Please explain the incremental $4,955,238.

Response:

The incremental $4,955,238 is due to the reclassification of assets in 2009 from Construction in Progress, which were not depreciable, to Miscellaneous Intangible Plant in-service additions which are depreciable.

b) The opening balance for 2010 is significantly lower than the closing balance for 2009 and the additions shown for 2009. Further, the net for depreciation adds in significant amounts (rather than subtracting amounts) for fully depreciated assets. Please explain the change in format used for 2010 and 2011.

Response:

Exhibit 4, Tab 7, Schedule 1.2, Table 5 and Table 6 reflected only the Accumulated Amortization relating to 2010 as the Company had restated the opening balance in all capital work accounts based on net book value (NBV) at January 1, 2010 as required by IFRS (specifically - IFRS 1 “First Time Adoption of International Financial Reporting Standards”).

Energy Probe Interrogatory # 42

Ref: Exhibit 4, Tab 7, Schedule 1.2 &

Exhibit 2, Tab 5, Schedule 1.0, Table 1

Please explain why the capital additions shown for 2006 through 2010 (Tables 1 through 5 in Exhibit 4, Tab 7, Schedule 1.2) are different from the capital additions shown in Tale 1 of Exhibit 2, tab 5, Schedule 1.0, while the 2011 test year figures are the same. In particular, please explain the addition of an incremental $5.2 million in 2010 for depreciation purposes over and above the capital additions shown in Schedule 1.0.

Response:

The additions shown in Tables 1 through 5 in Exhibit 4, Tab 7, Schedule 1.2 are net of disposals whereas Table 1 of Exhibit 2, Tab 5, Schedule 1.0 are only capital expenditures. The addition of $5.2 million in 2010 for depreciation purposes over and above the capital additions shown in Schedule 1.0 relates to the reclassification of Goreway TS station from construction in progress to a depreciable intangible asset, as it was put in service in 2010.

Energy Probe Interrogatory # 43

Ref: Exhibit 4, Tab 7, Schedule 1.2

Tables 1 through 4 (for 2006 through 2009) appear to use the half year rule for assets added in the current year. This is reflected in the column labeled "Total for Depreciation" and the formula that follows it that indicates 0.5 of the additions are added into the total for depreciation.

However, a review of the figures provided in Tables 5 & 6 (2010 and 2011) show that the half year rule has not been applied.

a) Please explain why HOBNI has not used the half year rule for additions in the current year in 2010 and 2011.

Response:

See response to question 24 of the OEB's IRs

The following versions of Tables 4 and 5 are with the half year rule applied to the additions in the current year.

Depreciation Expense 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,412,508		1,412,508	349,700	1,587,358	various	4,523
1808	Buildings and Fixtures	29,478,774		29,478,774	435,898	29,696,723	various	591,106
1815	Transformer Station Equipment - Normally Primary above 50 kV	12,011,917		12,011,917	659,356	12,341,595	various	395,503
1820	Distribution Station Equipment - Normally Primary below 50 kV	40,492,279		40,492,279	1,116,600	41,050,579	various	1,355,438
1830	Poles, Towers and Fixtures	61,098,800	4,551,784	56,547,016	6,712,536	59,903,284	25	2,396,131
1835	Overhead Conductors and Devices	19,376,229	373,822	19,002,407	1,790,835	19,897,824	25	795,913
1840	Underground Conduit	17,738,414	774,359	16,964,055	3,098,681	18,513,395	25	740,536
1845	Underground Conductors and Devices	215,034,537	13,404,597	201,629,940	10,178,876	206,719,378	25	8,268,775
1850	Line Transformers	88,592,205	10,901,156	77,691,049	4,376,562	79,879,330	25	3,195,173
1855	Services	23,014,363	1,026,647	21,987,716	661,552	22,318,492	25	892,740
1860	Meters	43,203,730	17,906,989	25,296,741	1,026,750	25,810,116	various	1,720,674
1908	Buildings and Fixtures	310,348	3,131	307,218	-	307,218	25	12,289
1915	Office Furniture and Equipment	1,702,247	1,335,067	367,179	528,000	631,179	10	63,118
1920	Computer Equipment - Hardware	3,199,798	2,291,910	907,888	840,400	1,328,088	5	265,618
1925	Computer Software	-	-	-	-	-	5	-
1930	Transportation Equipment	9,376,602		9,376,602	1,980,000	10,366,602	various	704,519
1935	Stores Equipment	219,670	56,279	163,391	-	163,391	10	16,339
1940	Tools, Shop and Garage Equipment	2,847,869	1,440,330	1,407,539	381,000	1,598,039	10	159,804
1950	Power Operated Equipment	37,250	1,360	35,890	-	35,890	8	4,486
1955	Communication Equipment	605,068	-	605,068	41,600	625,868	10	62,587
1960	Miscellaneous Equipment	140,957	(25)	140,982	-	140,982	10	14,098
1980	System Supervisory Equipment	4,511,464	1,683,246	2,828,218	101,000	2,878,718	15	191,915
1995	Contributions and Grants - Credit	(100,287,257)	(13,448,387)	(86,838,870)	(11,658,493)	(92,668,117)	25	(3,706,725)
2055	Construction Work in Progress--Electric	798,274		798,274	3,216,066	2,406,307	none	-
2040	Electric Plant Held for Future Use	3,369,797		3,369,797	-	3,369,797	none	-
1610	Miscellaneous Intangible Plant - TS CIP	5,118,257		5,118,257	-	5,118,257	none	-
1610	Miscellaneous Intangible Plant - Software CIP	84,843		84,843	-	84,843	none	-
1610	Miscellaneous Intangible Plant - TS in-service	3,045,640		3,045,640	5,268,063	5,679,672	various	204,165
1610	Miscellaneous Intangible Plant - Software in-service	1,940,555		1,940,555	961,600	2,421,355	various	285,563
	TOTAL	496,622,029	42,302,266	454,319,763	32,066,582	470,353,054		18,634,288

Depreciation Expense 2011

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,762,208		1,762,208	208,600	1,866,508	various	10,106
1808	Buildings and Fixtures	29,371,381		29,371,381	925,523	29,834,142	various	613,562
1815	Transformer Station Equipment - Normally Primary above 50 kV	13,214,564		13,214,564	1,666,324	14,047,726	various	447,576
1820	Distribution Station Equipment - Normally Primary below 50 kV	41,608,880		41,608,880	971,404	42,094,582	various	582,974
1830	Poles, Towers and Fixtures	67,811,336	16,108,311	51,703,025	5,703,841	54,554,945	42	1,298,927
1835	Overhead Conductors and Devices	21,167,064	2,827,672	18,339,392	1,067,069	18,872,926	50	377,459
1840	Underground Conduit	20,837,095	1,844,737	18,992,358	3,647,050	20,815,883	50	416,318
1845	Underground Conductors and Devices	225,213,413	41,885,292	183,328,121	13,701,644	190,178,943	35	5,433,684
1850	Line Transformers	92,968,767	32,507,327	60,461,440	6,252,444	63,587,662	40	1,589,692
1855	Services	23,675,915	9,948,147	13,727,768	767,000	14,111,268	50	282,225
1860	Meters	44,230,145	18,308,387	25,921,758	991,000	26,417,258	15	1,761,151
1908	Buildings and Fixtures	310,348	3,130	307,218	-	307,218	25	12,289
1915	Office Furniture and Equipment	2,230,247	1,340,668	889,579	168,475	973,817	10	97,382
1920	Computer Equipment - Hardware	4,040,198	2,724,787	1,315,411	305,200	1,468,011	5	293,602
1925	Computer Software	-	-	-	-	-	5	-
1930	Transportation Equipment	11,356,601		11,356,601	2,294,478	12,503,840	various	917,569
1935	Stores Equipment	219,670	56,279	163,391	-	163,391	10	16,339
1940	Tools, Shop and Garage Equipment	3,228,869	1,609,343	1,619,526	104,962	1,672,007	10	167,201
1950	Power Operated Equipment	37,250	1,360	35,890	-	35,890	8	4,486
1955	Communication Equipment	646,668	0	646,668	133,400	713,368	10	71,337
1960	Miscellaneous Equipment	140,982	0	140,982	-	140,982	10	14,098
1980	System Supervisory Equipment	4,612,464	78,448	4,534,016	501,000	4,784,516	7	683,502
1995	Contributions and Grants - Credit	(111,945,750)	(42,995,129)	(68,950,621)	(14,587,030)	(76,244,136)	25	(3,049,765)
2055	Construction Work in Progress--Electric	4,014,340		4,014,340	(1,261,441)	3,383,620	None	-
2040	Electric Plant Held for Future Use	3,369,797		3,369,797	-	3,369,797	None	-
1610	Miscellaneous Intangible Plant - TS CIP	5,118,257		5,118,257	-	5,118,257	None	-
1610	Miscellaneous Intangible Plant - Software CIP	84,843		84,843	-	84,843	None	-
1610	Miscellaneous Intangible Plant - TS in-service	8,313,703		8,313,703	-	8,313,703	various	332,189
1610	Miscellaneous Intangible Plant - Software in-service	2,902,155		2,902,155	554,800	3,179,555	various	238,810
	TOTAL	528,688,302	86,248,761	442,439,541	24,115,743	454,497,412		12,612,711

b) What is the net increase in the 2011 rate base as a result of applying the half year rule to 2010 and 2011?

Response:

Please see reply for 5c.

c) What is the net decrease in the depreciation expense in 2011 as a result of applying the half year rule to 2010 and 2011?

Response:

Please see reply for 5d.

Energy Probe Interrogatory # 44

Ref: Exhibit 4, Tab 7, Schedules 1.0 & 1.2

a) The depreciation expense shown in Table 5 for 2010 in Schedule 1.2 is $12.2 million, a decrease of $5.3 million from the $17.5 million shown for 2009. How much of this decrease is directly attributable to the new proposed depreciation rates for 2010?

Response:

$5.5M of the decrease is directly attributable to the new proposed depreciation rates for 2010. Under the old rates the amount would be $17.7M and under the new rates the amount is $12.2M.

b) Please explain why HOBNI is proposing the Board approve the proposed depreciation rates retroactively to 2010?

Response:

HOBNI used the revised depreciation rates for comparative purposes only. HOBNI has now submitted revised 2010 depreciation calculations using the current approved rates

c) What is the impact on the 2011 rate base if the new depreciation rates are applied beginning January 1, 2011 and the existing depreciation rates were continued to be used in 2010?

Response:

Please see VECC IR 71.

d) Based on existing depreciation rates, and application of the half year rule on capital additions in 2010, please indicate the total depreciation expense that would be recorded for 2010 and compare this to the amount that would be recorded for 2010 if the new depreciation rates were applied, but the half year rule was also applied.

Response:

The difference is $5.3M. Under the old rates, the amount would be $17.7M compared to $12.4M under the new rates.

Energy Probe Interrogatory # 45

Ref: Exhibit 4, Tab 8, Schedule 1.1

Please explain why HOBNI has not calculated the CCA excluding the half year rule for Class 52 in 2011, as it did in 2010.

Response:

HOBNI is in agreement that the half year rule was not required for Class 52 in 2011. The revenue requirement model will be adjusted by the $11,000 understatement of CCA.

Energy Probe Interrogatory # 46

Ref: Exhibit 4, Tab 8, Schedule 1.0

a) Please confirm that the Ontario surtax claw-back on the first $500,000 of taxable income was eliminated effective July 1, 2010 and that the provincial income tax rate on the first $500,000 of taxable income was reduced to 4.50%.

Response:

Hydro One Brampton qualifies as a Canadian Controlled Private Corporation; however, it does not qualify for the small business deduction as its total capital employed in Canada for itself and associated corporations exceeds $10 million.

b) Has HOBNI included a tax reduction of $36,250 related to the Ontario small business tax rate on the first $500,000 in taxable income (calculated as $500,000 times the difference between 11.75% and 4.50%)? If not, why not?

Response:

The small business rate does not apply to HOBNI, see a) above.

c) Has HOBNI made any adjustments to the PILs calculation to reflect the Ontario apprenticeship training tax credit and/or the federal apprenticeship job creation tax credit? If not, why not?

Response:

No adjustment was made to the PILs calculation to reflect the ON or Federal apprenticeship job credit as the 2008 tax return claim was negligible Ontario $16, 037, Federal $9,639.

d) Please provide a calculation of the Ontario apprenticeship training tax credit, showing the number of eligible positions and the amount that can be claimed for each position for the 2011 test year.

Response:

See c) above

e) Please provide a calculation of the Federal Apprenticeship Job Creation Tax Credit, showing the number of eligible positions and the amount that can be claimed for each position for the 2011 test year.

Response:

See c) above

f) Has HOBNI included any tax credits related to the cooperative education tax credit? If not, why not? Please show the number of positions that qualify for the credit and the average amount of the credit, along with the total credit that could be claimed in 2011.

Response:

No tax credits related to the cooperative education tax credit were reflected as the 2008 claim of $3,000 was considered immaterial.

Energy Probe Interrogatory # 47

Ref: Exhibit 4, Tab 8, Schedule 3.0

a) Please explain the reference to the 2010 test year on line 4 of page 1.

Response:

Line 4 of page 1 refers to the 2011 test year..

b) Please explain the reference to the 3.5% increase in property taxes noted at line 4 of page 1 when the increase in Table 2 is 2.3% for both 2010 and 2011.

Response:

The statement should have read as follows: "Hydro One Brampton estimated a 2.3% increase in property taxes…"

c) Please update Table 1 for any actual property assessment values that are now available for 2010.

Response:

Table 1: Properties and Property Assessment Values for 2006-2011

Location.		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011
175 Sandalwood Pky	ADMIN	14,702,000	14,702,000	14,702,000	13,609,250	14,163,500	14,717,750
25 Coventry Road	MS21	424,000	424,000	424,000	474,750	525,500	576,250
6 Easton Place	MS18	242,000	242,000	242,000	263,250	284,500	305,750
149 Hansen Road N.	MS12	166,000	166,000	166,000	171,500	177,000	182,500
18 Grassmear Cres	MS20	165,000	165,000	165,000	167,500	170,000	172,500
398 Orenda Road	MS17	234,000	234,000	234,000	248,000	262,000	276,000
9066 Dixie Road	MS19	421,000	421,000	421,000	455,500	490,000	524,500
125 Team Canada Drive	MS22	269,000	269,000	269,000	285,750	302,500	319,250
44 Church Street West	MS2	58,000	58,000	58,000	61,500	65,000	68,500
8 Elizabeth St N.	MS1/13	179,000	179,000	179,000	187,250	195,500	203,750
8057 Mc Laughlin Road S.	MS14	163,000	163,000	163,000	169,750	176,500	
230 Steeles Ave W	MS10	147,000	147,000	147,000	152,250	157,500	162,750
212 Rutherford Road S.	MS11	177,000	177,000	177,000	185,500	194,000	202,500
67 Eastern Ave.	MS3	65,000	65,000	65,000	68,250	71,500	74,750
Kennedy Road S / 273-2 Glidden Road	MS6	48,500	48,500	48,500	51,875	55,250	58,625
1100 Steeles W.	JYTS	593,000	593,000	593,000	650,750	708,500	766,250
O Archdekin Drive	Decommissi	188,000	188,000	188,000	203,250	218,500	249,000
8686 McLaughlin Road S.	MS8						
TOTAL		**18,241,500**	**18,241,500**	**18,241,500**	**17,405,875**	18,217,250	18,860,625

d) Please update Table 2 for any actual property tax that is now available for 2010.

Response:

Table 2: Actual and Estimated Amounts for Property Taxes

Location.	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Test Year
175 Sandalwood Pkwy	396,529	405,981	415,356	372,726	371,440	390,069
25 Coventry Road	13,045	13,357	13,645	14,830	15,758	15,520
6 Easton Place	7,446	7,624	7,788	8,223	8,531	8,606
149 Hansen Road N.	5,107	5,230	5,342	5,357	5,308	5,606
18 Grassmear Cres	5,077	5,198	5,310	5,232	5,098	5,476
398 Orenda Road	7,199	7,372	7,531	7,747	7,857	8,107
9066 Dixie Road	12,953	13,263	13,549	14,229	14,694	14,891
125 Team Canada Drive	8,276	8,474	8,657	8,926	9,071	9,341
44 Church Street West	1,784	1,827	1,867	1,921	1,949	2,010
8 Elizabeth St N.	5,507	5,639	5,761	5,849	5,863	6,121
8057 Mc Laughlin Road S.	5,015	5,135	5,246	5,303	5,293	5,549
230 Steeles Ave W	4,523	4,631	4,731	4,756	4,723	4,977
212 Rutherford Road S.	5,446	5,576	5,696	5,795	5,818	6,064
67 Eastern Ave.	2,000	2,048	2,092	2,132	2,144	2,231
Kennedy Road S / 273-2 Glidden Road	1,492	1,528	1,561	1,620	1,657	1,696
1100 Steeles W.	18,042	18,681	19,084	20,328	21,246	21,274
O Archdekin Drive	4,049	4,146	4,235	4,444	4,587	4,651
TOTAL	503,490	515,710	527,448	489,418	491,036	512,190

Energy Probe Interrogatory # 48

Ref: Exhibit 5, Tab 1, Schedule 2.0

a) Does HOBNI expect the ROE for 2011 to be set based on the January 2010 market interest rate information, as stated at lines 9-10 of page 1? Should this be January 2011?

Response:

Hydro One Brampton expects the ROE to be based on the September 2010 Consensus Forecast, for setting rates in January 2011.

b) If the reference noted above should be to market interest rate information available in January 2011, how does HOBNI expect rates to be determined and implemented for January 1, 2011?

Response:

See part A

c) Does HOBNI agree that the Board should use market interest rate information available in September 2010 (3 months prior to the implementation date) to determine the ROE? If not, why not?

Response:

Yes.

d) Does HOBNI agree that the Board should use market interest rate information available in September 2010 (3 months prior to the implementation date) to determine the short-term debt rate? If not, why not?

Response:

Yes.

e) Has HOBNI obtained any long term debt to date in 2010? If yes, please provide the details, including the amount and the rate.

Response:

No.

f) Please update Table 3 to reflect the most recent information available.

Response:

Please see response in Exhibit 12, Tab 1, Schedule 36, part (c).

g) What is the prescribed interest rate for 2010 for CWIP? What is the impact on the calculation of the 2011 rate base of using the Board approved CWIP figures (assuming the Q4 rate for 2010 is equal to the Q3 rate - unless it is available at the time of response) in place of the 4.91% used by HOBNI for 2010?

Response:

The prescribed CWIP interest rate for 2010 Q3 is 4.66% and for 2010 Q4 4.01%. There is no impact on rate base; Construction Work in Process (CWIP) is excluded from fixed assets in the determination of rate base

h) Please explain why HOBNI intends to opt for 30 year debt resulting in all of its debt being 30 years in length, rather than a mix of shorter maturities?

Response:

Debt with a term of 30 years is consistent with the long life of assets. As stated on page 10 of The Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors (dated December 20, 2006). "For rate-making purposes, the term of the debt should be assumed to be compatible with the life of the assets. With electricity distributors, the asset life can extend beyond 30 years."

i) Has HOBNI investigated the potential of replacing the existing $143 million debt instrument with a mixture of terms at rates lower than 6.95%? If not, why not? If yes, why is HOBNI not proposing to do this?

Response:

Please see response to Exhibit 12, Tab 4, Schedule 33 part (d)

Energy Probe Interrogatory # 49

Ref: Exhibit 8, Tab 5, Schedule 1, page 4

Please explain how the total loss factor is applied to the microFit generator service classification.

Response:

The total loss factor is not applied to the microFit generator service classification

Energy Probe Interrogatory # 50

Ref: Exhibit 9, Tab 1, Schedule 3.0

HOBNI is requesting a variance account for the losses on early retirement. Is HOBNI also requesting a variance account for the gains in excess of net book value upon retirement? If not, why not?

Response:

HOBNI is requesting a deferral account for these losses, not a variance account. HOBNI is also requesting that this deferral account be used for gains in excess of net book value upon retirement.

Energy Probe Interrogatory # 51

Ref: Exhibit 1, Tab 2, Schedule 1.0 &

EB-2009-0423 Alignment of Rate Year with Fiscal Year for Electricity Distributors dated April 15, 2010

At Exhibit 1, Tab 2, Schedule 1.0, HOBNI indicates that it is seeking revised distribution rates to be implemented on January 1, 2011.

a) Please confirm that HOBNI's current rate year begins May 1.

Response:

Yes: Hydro One Brampton's rate year begins May 1

b) In the April 15, 2010 letter related to the alignment of the rate year with the fiscal year, the Board stated that it:

"...expects the distributor to include analysis of the benefits and ratemaking implications, if any, of the alignment as part of its application."

The Board included examples of issues that should be addressed in Appendix B to the letter.

Where has HOBNI provided its analysis/evidence in support of the requested change in the rate year?

Response:

See response to VECC Q1b

c) In the absence of any analysis, why should the Board approve the requested change?

Response:

In response to b and c – Hydro One Brampton provided responses to the Board in a letter dated February 17, 2010 that addressed the examples of issues that the Board requested to assist the Board in making a determination on this issue. The company's position is repeated in response VECC IR Q1b.

Energy Probe Interrogatory # 52

Ref: Exhibit 9, Tab 1, Schedule 1

The Group 2 total account balance to be recovered from ratepayers is more than $4.3 million. This balance relates to balances that accrued prior to the implementation of the HST on July 1, 2010. Please explain:

a) Whether HOBNI believes that this balance to be recovered from customers should attract the 5% GST of the 13% HST? Please explain, including any discussions with Revenue Canada.

Response:

Rate riders are included in distribution charges and HOBNI is required by taxation authorities to apply all applicable taxes, including HST. There has been no discussion with the Canada Revenue Agency on this matter.

b) Can HOBNI accommodate billing the rate rider portion of the bill associated with the deferral and variance account balances at the 5% GST, while the remainder of the bill attracts the 13% HST?

Response:

HOBNI billing systems cannot accommodate this functionality.

Energy Probe Interrogatory # 53

Ref: September 2, 2010 Letter re Update to 2011 Cost of Service Filing &

Exhibit 1, Tab 2, Schedule 3.1

a) Please explain why there does not appear to be any change in the Selected Delivery Charge and Bill Impacts per Draft Rate Order (page 9 of the Revenue Requirement Work Form) despite the reduction in the revenue requirement of $3.9 million from $4.042 million to $0.182 million.

Response:

At the time Hydro One Brampton submitted its "High Level" CGAAP Revenue Requirement related information in its September 2, 2010 filing, Hydro One Brampton had not updated its Cost of Service models including its rate design calculations needed to complete this sheet Revenue Requirement Work Form.

As detailed computations were required for its Cost of Service models and in response to Interrogatories, Hydro One Brampton has now updated its revenue requirement using detailed line by line account information in its Revenue Requirement model. In addition, the Cost Allocation and Rate Design models have been rerun and rate impact analyses information is now available in this filing. Hydro One Brampton has updated the Selected Delivery Charge and Bill Impacts per Draft Rate Order (page 9 of the Revenue Requirement Work Form). The updated Revenue Requirement Work Form can be found in **Appendix AX**

b) With respect to the Taxes/PILs calculations shown in the Revenue Requirement Work Form, please explain what is driving the change in the adjustments required to arrive at taxable utility income from ($6,893,703) to ($7,471,354). Please also show how the change in the adjustments relate to the changes shown Attachment A to the September 2, 2010 letter.

Response:

Hydro One Brampton has updated its revenue requirement model and all changes in relation to the September 2nd letter have been factored into the revised revenue requirement model. The updated Revenue requirement model supersedes the September 2, 2010 update. However as the data pertaining to this interrogatory was readily available it has been submitted.

The tax adjustments were revised to $7,471,354; originally tax adjustments were $6,893,703. A decrease of $371,305 to amortization of tangible assets coupled with an increase of $206,345 to capital cost allowance accounted for the $577,651 change in the tax adjustments to accounting income.

Tax Adjustments to Accounting Income			
	Original Tax Adjustments	**Revised Tax Adjustments**	**Difference**
Additions:			
Amortization of tangible assets	$ 10,924,906.93	$ 10,553,601.41	$ (371,305.52)
Amortization of intangible assets	$ 567,671.89	$ 567,671.89	$ -
Charitable donations	$ 2,650.00	$ 2,650.00	$ -
Non-deductible meals and entertainment expense	$ 15,403.00	$ 15,403.00	$ -
Reserves from financial statements- balance at end of year	$ 8,646,000.00	$ 8,646,000.00	$ -
Capital items expensed	$ 276,138.00	$ 276,138.00	$ -
Other Additions	$ 44,746.00	$ 44,746.00	$ -
Total Additions	$ 20,477,515.82	$ 20,106,210.30	$ (371,305.52)
Deductions:			
Capital cost allowance from Schedule 8	$ 18,792,258.00	$ 18,998,603.97	$ 206,345.97
Cumulative eligible capital deduction from Schedule 10	$ 58,437.82	$ 58,437.82	$ -
Reserves from financial statements - balance at beginning of year	$ 8,328,000.00	$ 8,328,000.00	$ -
Other Deductions	$ 192,523.00	$ 192,523.00	$ -
Total Deductions	$ 27,371,218.82	$ 27,577,564.79	$ 206,345.97
Total Tax Adjustments	$ (6,893,703.00)	$ (7,471,354.48)	$ (577,651.48)

c) Please explain how the figures in the "Adjusted Revenue Requirement" column of Table 1 in the September 2, 2010 letter are calculated.

Response:

Hydro One Brampton has updated its revenue requirement model and all changes in relation to the September 2nd letter have been factored into the revised revenue requirement model. The updated revenue requirement model supersedes the September 2, 2010 update. However as the data pertaining to this interrogatory was readily available it has been submitted.

The "Adjusted Revenue Requirement" figures from Table 1 in the September 2, 2010 letter are calculated in Appendix A of the same letter for each of the three revisions to revenue requirement based on the following:

Rate base – See Table A below

Amortization expense – See Table A below

Capital cost allowance – See Table B below (used to calculate adjustments to accounting income)

OM&A expenses – See Table A below (changes to OM&A detailed)

Return on rate base – As calculated in Appendix A in the September 2, 2010 letter, reproduced below.

Payments in lieu of taxes – As calculated in Appendix A in the September 2, 2010 letter, reproduced below.

Revenue Deficiency - As calculated in Appendix A in the September 2, 2010 letter, reproduced below.

Table A - Adjustment to Rate Base, Fixed Assets and Controllable Costs for 2011 Test Year

Fixed Asset Continuity	2011	Depreciation - Change in Half Year Rule	Expense Indirect Overheads	Gains/Losses on Early Retirement of Assets	2011 Adjusted
Gross Fixed Assets - Opening	$ 288,315,027.76				$ 288,315,027.76
Additions	$ 20,996,024.50		$ 3,100,000.00		$ 24,096,024.50
Disposals	$ -			$ 290,000.00	$ 290,000.00
Adjustments	$ 1,249,899.19				$ 1,249,899.19
Gross Fixed Assets - Closing	$ 310,560,951.45	$ -	$ 3,100,000.00	$ 290,000.00	$ 313,950,951.45
Gross Fixed Assets - Average	$ 299,437,989.61	$ -	$ 1,550,000.00	$ 145,000.00	$ 301,132,989.61
Accumulated Depreciation - Opening	$ 12,206,510.38				$ 12,206,510.38
Additions	$ 12,430,973.40	$ (500,000.00)	$ 128,694.48		$ 12,059,667.88
Disposals	$ -				$ -
Adjustments	$ -				$ -
Accumulated Depreciation - Closing	$ 24,637,483.78	$ (500,000.00)	$ 128,694.48	$ -	$ 24,266,178.26
Accumulated Depreciation - Average	$ 18,421,997.08	$ (250,000.00)	$ 64,347.24	$ -	$ 18,236,344.32
Net Book Value - Opening	$ 276,108,517.38	$ -	$ -	$ -	$ 276,108,517.38
Net Book Value - Closing	$ 285,923,467.67	$ 500,000.00	$ 2,971,305.52	$ 290,000.00	$ 289,684,773.19
Net Book Value - Average	$ 281,015,992.53	$ 250,000.00	$ 1,485,652.76	$ 145,000.00	$ 282,896,645.29
Depreciation Expense to Gross Fixed Asset Ratio	24.09				
Controllable Costs					
Distribution Expenses - Operation	$ 6,854,992.03		$ (839,716.43)	$ (290,000.00)	$ 5,725,275.60
Distribution Expenses - Maintenance	$ 4,035,503.00		$ (494,337.29)		$ 3,541,165.71
Billing and Collecting	$ 5,656,663.00		$ (692,924.64)		$ 4,963,738.36
Community Relations	$ 640,000.00		$ (78,398.12)		$ 561,601.88
Administrative and General Expenses	$ 8,119,570.00		$ (994,623.52)		$ 7,124,946.48
Total OM&A	$ 25,306,728.03	$ -	$ (3,100,000.00)	$ (290,000.00)	$ 21,916,728.03
Power Supply Expenses	$ 335,078,839.00				$ 335,078,839.00
Total Working Capital Expenses	$ 360,385,567.03	$ -	$ (3,100,000.00)	$ (290,000.00)	$ 356,995,567.03
Working Capital Allowance	$ 54,057,835.05	$ -	$ (465,000.00)	$ (43,500.00)	$ 53,549,335.05
Average Net Book Value of Fixed Assets	$ 281,015,992.53	$ 250,000.00	$ 1,485,652.76	$ 145,000.00	$ 282,896,645.29
Rate Base	$ 335,073,827.58	$ 250,000.00	$ 1,020,652.76	$ 101,500.00	$ 336,445,980.34
Depreciation Expense					
Per Additions to Accumulated Depreciation	$ 12,430,973.40	$ (500,000.00)	$ 128,694.48	$ -	$ 12,059,667.88
Transportation Equipment	$ (917,569.28)				$ (917,569.28)
Stores Equipment	$ (16,339.09)				$ (16,339.09)
Power Operated Equipment	$ (4,486.21)				$ (4,486.21)
Removal Costs	$ 1,002,000.00				$ 1,002,000.00
Total Depreciation Expense	$ 12,494,578.82	$ (500,000.00)	$ 128,694.48	$ -	$ 12,123,273.30

Table B - Adjustments to Capital Cost Allowance

	2011	Depreciation - Change in Half Year Rule	Expense Indirect Overheads	Gains/Losses on Early Retirement of Assets	2011 Adjusted
UCC - Opening	$ 276,527,961				$ 276,527,961
Additions	$ 20,827,339		$ 3,100,000		$ 23,927,339
Proceeds on Dipsosals	$ -				$ -
CCA on Opening UCC	$ (17,405,923)				$ (17,405,923)
CCA on Additions	$ (1,386,335)		$ (206,346)		$ (1,592,681)
UCC - Closing	$ 278,563,043	$ -	$ 2,893,654	$ -	$ 281,456,697
CEC - Opening	$ 708,312				$ 708,312
Additions	$ 126,514				$ 126,514
Proceeds on Dipsosals	$ -				$ -
CEC Disposals on Opening CEC	$ (49,582)				$ (49,582)
CEC Disposals on CEC Additions	$ (8,856)				$ (8,856)
CEC - Closing	$ 776,388	$ -	$ -	$ -	$ (776,388)
Average CCA on Opening UCC	-6.3%				
Average CCA on Additions	-6.7%				

Appendix A - 2011 Revenue Requirement Adjustment - Revenue Deficiency Determination

Description	Revenue Requirement Filed	Adjustments to Revenue Requirement: Depreciation - Change in Half Year Rule	Expense Indirect Overheads	Gain/Loss on Retirement	Total Adjustments	Adjusted Revenue Requirement
Revenue						
Revenue Deficiency	**4,042,406**	**(673,366)**	**(2,905,945)**	**(280,460)**	**(3,859,770)**	**182,636**
Distribution Revenue	58,552,937	0	0	0	0	58,552,937
Other Operating Revenue (Net)	3,986,412	0	0	0	0	3,986,412
Total Revenue	**66,581,755**	**(673,366)**	**(2,905,945)**	**(280,460)**	**(3,859,770)**	**62,721,985**
Costs and Expenses						
Administrative & General, Billing & Collecting	14,416,233	0	(1,765,946)	0	(1,765,946)	12,650,287
Operation & Maintenance	10,890,495	0	(1,334,054)	(290,000)	(1,624,054)	9,266,441
Depreciation & Amortization	12,494,579	(500,000)	128,694	0	(371,306)	12,123,273
Capital Taxes	0	0	0	0	0	0
Deemed Interest	12,964,060	9,673	39,489	3,927	53,089	13,017,149
Total Costs and Expenses	**50,765,367**	**(490,327)**	**(2,931,816)**	**(286,073)**	**(3,708,217)**	**47,057,150**
Utility Income Before Income Taxes	**15,816,388**	**(183,038)**	**25,872**	**5,613**	**(151,553)**	**15,664,835**
Income Taxes:						
Corporate Income Taxes	2,520,659	(192,958)	(14,628)	1,586	(206,000)	2,314,658
Total Income Taxes	**2,520,659**	**(192,958)**	**(14,628)**	**1,586**	**(206,000)**	**2,314,658**
Utility Net Income	**13,295,729**	**9,920**	**40,500**	**4,028**	**54,447**	**13,350,176**
Capital Tax Expense Calculation:						
Total Rate Base	335,073,828	250,000	1,020,653	101,500	1,372,153	336,445,980
Exemption	0	0	0	0	0	0
Deemed Taxable Capital	**335,073,828**	**250,000**	**1,020,653**	**101,500**	**1,372,153**	**336,445,980**
Ontario Capital Tax	0	0	0	0	0	0
Income Tax Expense Calculation:						
Accounting Income	15,816,388	(183,038)	25,872	5,613	(151,553)	15,664,835
Tax Adjustments to Accounting Income	(6,893,703)	(500,000)	(77,651)	0	(577,651)	(7,471,354)
Taxable Income	**8,922,685**	**(683,038)**	**(51,780)**	**5,613**	**(729,205)**	**8,193,480**
Income Tax Expense	2,520,659	(192,958)	(14,628)	1,586	(206,000)	2,314,658
	28.25%	0.00%	0.00%	0.00%	0.00%	28.25%
Actual Return on Rate Base:						
Rate Base	335,073,828	250,000	1,020,653	101,500	1,372,153	336,445,980
Interest Expense	12,964,060	9,673	39,489	3,927	53,089	13,017,149
Net Income	13,295,729	9,920	40,500	4,028	54,447	13,350,176
Total Actual Return on Rate Base	**26,259,789**	**19,593**	**79,989**	**7,955**	**107,536**	**26,367,325**
Actual Return on Rate Base	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%
Required Return on Rate Base:						
Rate Base	335,073,828	250,000	1,020,653	101,500	1,372,153	336,445,980
Return Rates:						
Return on Debt (Weighted)	6.45%	6.45%	6.45%	6.45%	6.45%	6.45%
Return on Equity	9.92%	9.92%	9.92%	9.92%	9.92%	9.92%
Deemed Interest Expense	12,964,060	9,673	39,489	3,927	53,089	13,017,149
Return On Equity	13,295,729	9,920	40,500	4,028	54,447	13,350,176
Total Return	**26,259,789**	**19,593**	**79,989**	**7,955**	**107,536**	**26,367,325**
Expected Return on Rate Base	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%

Tax Exhibit

Deemed Utility Income	13,295,729	9,920	40,500	4,028	54,447	13,350,176
Tax Adjustments to Accounting Income	(6,893,703)	(500,000)	(77,651)	0	(577,651)	(7,471,354)
Taxable Income prior to adjusting revenue to PILs	**6,402,026**	**(490,080)**	**(37,152)**	**4,028**	**(523,204)**	**5,878,822**
Tax Rate	28.25%	0.00%	0.00%	0.00%	0.00%	28.25%
Total PILs before gross up	**1,808,572**	**(138,448)**	**(10,495)**	**1,138**	**(147,805)**	**1,660,767**
Grossed up PILs	**2,520,659**	**(192,958)**	**(14,628)**	**1,586**	**(206,000)**	**2,314,658**

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Energy Probe Interrogatory # 54

Ref: September 2, 2010 Letter re Update to 2011 Cost of Service Filing

With respect to the increase in the OMERS pension cost increase please provide the following.

a) The amount currently included in the calculation of the test year revenue requirement for these costs.

Response:

The estimated amount is $0.4M.

b) Is the $1.0 M increase an annual increase, or the expected increase in aggregate over the 2011 through 2013 period?

Response:

The estimated $1.0M increase is an aggregate for the years 2011-2013.

c) If the approval for the requested deferral account is denied and these incremental costs are included as part of the 2011 revenue requirement, does HOBNI agree that a deferral account would be required to track the reduction in costs post 2013 and prior to the next rebasing application?

Response:

Yes.

d) Would HOBNI accept the inclusion of the forecast incremental costs in the 2011 revenue requirement, along with a variance account to track the differences between the forecasted amount and actual costs in 2011 and each subsequent year until the next rebasing application? If not, why not?

Response:

YES.