EB-2010-0132

Ontario Energy Board

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

AND IN THE MATTER OF an application by Hydro One Brampton Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2011.

ENERGY PROBE RESEARCH FOUNDATION ("ENERGY PROBE") CROSS-EXAMINATION COMPENDIUM

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Information submitted in the June 30, 2010 application has been superseded through the submissions of the models noted above or through responses to Interrogatories: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

Technical Conference Exhibit JT 1.21

To provide management analysis, presentation, or some document which provides reasoning as to how those percentages were arrived at for SCADA, renewable energy investments, and expansions.

Response:

The following is the analysis used to determine the Cost Allocation Percentages as shown in the Table below:

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

The criteria used for the purpose of estimating the direct benefits included the following:

1. New Assets to accommodate Renewable Generators
    a. Portion of Assets used by Load Customer
    b. Portion of Asset used by Generator
2. Asset Replacement to accommodate Renewable Generators
    a. Age of Assets
    b. Asset Condition
    c. Asset Depreciation/Remaining life
3. Size of FIT Generators
4. Quantity of potential Generator Connections
5. Customer Load Growth
6. Service Life Improvements
7. Current Design of the Distribution System
8. Operating Practice

Analysis

Projects:

Criteria Question	Expansion	Renewable Enabling Improvements	SCADA
Are New Assets Required to Accommodate	Yes – New transformers will accommodate generator connections.	Yes – Monitoring and communication equipment.	Yes – these SCADA installations are chosen primarily based on generator connections.

Generators?			
Are existing Assets being replaced to Accommodate Generators?	Yes – Existing transformers which served only load customers are required to be upgraded to accommodate the generators.	No	No
Sizes of Generations?	250-500 kW	>249 kW	>75 kW
Quantity of Generators?	Density in some areas of 5-7 generators on one feeder.	Requirement on all generators >249 kW	Density in some areas of 5-7 generators on one feeder.
Load Growth?	<1%	N/A	Feeder loading is a factor for prioritizing.
Service Life Improvements?	Yes	N/A	Yes
Current Design of System?	N/A	N/A	We already have a well developed SCADA system.
Operating Practice?	N/A	N/A	To ensure we can provide maintenance to load customers while still having the generators supply power.
Analysis	The transformers are upgraded because of the generators. Investment is seen to benefit both load customer and generators. The transformers being replaced have an average in-service life of 15 years. The normal service life of a transformer is 40 years.	Monitoring and communication system to be installed on all generator connections which are greater than 249 kW. This is a requirement from the Provincial Transmitter.	These SCADA installations are to allow for proper connection and operation of Generators. These installs are initiated due to generators; however they do benefit load customers from an Operational/Reliability side.
Direct Benefit	A. New assets that	1. New assets -	A. New assets that

Percentage Calculations	benefit both the generators and load customers, investment will be shared equally. B. Replacements of assets, in this case 15 year old transformers being replaced before their time will have a benefit to the load customer = 15/40 = 37.5%. C. Therefore, Direct Benefit to Load Customers is A*B = 50% * 37.5% = **18.75%**	Monitoring & Communication system benefits the generator 100% of the time. This asset offers no benefit to load customers. 2. No replacement of existing assets. 3. Therefore, Direct Benefit to Load Customers is = **0%**	benefit both the generators and the load customers, this investment should be shared equally. B. No replacement of existing assets. C. Therefore, Direct Benefit to Load Customers = **50%**

Technical Conference Exhibit KT 1.2

HOBNI Green Energy Investment 2010	Allocation of Cost Responsibility		
	Generator	Provincial Ratepayers	HOBNI Customers
OM&A	$250K	-	-
Expansions (up to threshold)	-	-	-
Renewable Enabling Improvements	-	$251K	-
Smart Grid (SCADA Only)	-	$294.5K	$294.5K
Smart Grid (Other)			$16K

545.5 + 310.5 = 856.0

Hydro One Brampton Networks Inc.
EB-2010-0132
Exhibit KT
Tab 1
Schedule 3.0
Filed: 18 October 2010

Technical Conference Exhibit KT 1.3

TABLE IN REFERENCE TO VECC IR NO.28

Allocation of Cost Responsibility															
HOBNI Green Energy Investment	**2011**			**2012**			**2013**			**2014**			**2015**		
	Gen	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**	**Gen**	**Prov**	**HOB**
OM&A	$250k	-	-	$250k	-	-	$250k	-	-	$250k	-	-	$250k	-	-
Expansions (up to threshold)	-	$134k	$31k	-	$137	$32k	-	$140k	$32k	-	$142k	$33k	-	$145k	$34k
Renewable Enabling Improvements	-	$83k	-	-	$84k	-	-	$86k	-	-	$88k	-	-	$89k	-
Smart Grid (SCADA Only)	-	$165k	$165k	-	$169k	$169k	-	$172k	$172k	-	$176k	$176k	-	$179k	$179k
Smart Grid (Other)	-	-	$330k	-	-	$337k	-	-	$344k	-	-	$351k	-	-	$358k

382.0+526.0= 908.0

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**

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**

Vulnerable Energy Consumers Coalition Interrogatory #2

Reference: **Exhibit 1, Tab 1, Schedule 12, page 1**

a) Please clarify whether for 2011, Brampton is proposing to:

- Reduce the OM&A and Capital Expenditures included in the Application for the test year in order to reflect the HST input tax credit, or
- Not reduce the OM&A & Capital Expenditures for 2011 but track the amounts concerned in Deferral Account 1592 for future disposition.

Response:

The 2011 OM&A and Capital Expenditures reflect expected actual costs. For 2011 HOBNI is proposing to track the amounts required in a deferral account.

b) If the latter, what is the forecast amount of "PST" included in the 2011 OM&A and Capital Spending?

Response:

HOBNI did not forecast the amount of "PST" which will no longer included in 2011 OM&A and Capital Expenditures.

Technical Conference Exhibit JT 1.1

Methodology to Determine the Cost Categories in OM&A and Capital Expenditures where HST Adjustment is Expected

Response:

The 2011 Businesss Plan instructions required HST savings to be excluded in the cost amounts for 2011, A review of the 2011 OM&A costs revealed that there is little evidence to support that the savings were excluded from the amounts budgeted. There may be areas where PST was excluded but this cannot be quantified.

A review of capital expenditures revealed that HST savings we not excluded from inventory and equipment. HST savings were deducted from amounts budgeted for all direct purchases.

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.

Technical Conference Exhibit JT 1.7

To Advise for Last Historical year PST Paid on OM&A Expenses and PST Paid on Capital Expenditures

Response:

The PST paid on OM&A and capital expenditures in 2009 is estimated at $86,000 and $1,078,000 respectively.

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

Table 3: 2011 Cost of Power Forecast Calculation

Forecast Unit Prices:

Commodity Price	6.94
Wholesale Market Services	0.0052
Rural Rate Protection	0.001
Transmision Network Service Charge	2.97
Transmission Line Connection	0.73
Transmission Transformation Connection	1.71

Month	Forecast GWHRS	Transmission Network Service Charge Demand MW	Transmission Line Connection Demand MW	Transmission Transformation Connection Demand MW	Commodity Costs	Wholesale Martket Service Charges	Rural Rate Protection	Transmission Network	Transmission Connection	Total Cost of Power
JAN	336.8797427	613,800	644,305	543,677	23,372,717	1,751,775	336,880	1,822,986	1,400,031	28,684,388
FEB	307.1738417	613,800	644,305	543,677	21,311,721	1,597,304	307,174	1,822,986	1,400,031	26,439,216
MAR	326.4853857	599,478	629,272	530,992	22,651,556	1,697,724	326,485	1,780,450	1,367,364	27,823,579
APR	298.2154197	537,075	563,767	475,718	20,690,186	1,550,720	298,215	1,595,113	1,225,027	25,359,261
MAY	308.8050867	603,570	633,567	534,616	21,424,897	1,605,786	308,805	1,792,603	1,376,697	26,508,789
JUN	329.0247347	757,020	794,643	670,535	22,827,736	1,710,929	329,025	2,248,349	1,726,705	28,842,744
JUL	353.3604327	767,250	805,382	679,597	24,516,147	1,837,474	353,360	2,278,733	1,750,039	30,735,753
AUG	351.9643947	777,480	816,120	688,658	24,419,290	1,830,215	351,964	2,309,116	1,773,373	30,683,957
SEP	307.7912637	644,490	676,521	570,861	21,354,558	1,600,515	307,791	1,914,135	1,470,033	26,647,032
OCT	314.9478297	562,650	590,613	498,371	21,851,080	1,637,729	314,948	1,671,071	1,283,362	26,758,189
NOV	317.8254917	603,570	633,567	534,616	22,050,733	1,652,693	317,825	1,792,603	1,376,697	27,190,551
DEC	346.0638187	618,915	649,675	548,208	24,009,908	1,799,532	346,064	1,838,178	1,411,698	29,405,379
Total	**3898.5374420**	**7,699,098**	**8,081,738**	**6,819,526**	**270,480,528**	**20,272,395**	**3,898,537**	**22,866,321**	**17,561,058**	**335,078,839**

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.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2009)

RPP Supply Cost Summary for the period from May 1, 2010 through April 30, 2011		
Forecast Wholesale Electricity Price		$36.66
Load-Weighted Price for RPP Consumers ($ / MWh)		$39.51
Impact of the Global Adjustment ($ / MWh)	+	$27.72
Total Contract Cost		$69.73
Market Value		($42.01)
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.14
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$69.38**

Note: The Market Value of $42.01/MWh is greater than either the Forecast Wholesale Electricity Price or the Load-Weighted Price for RPP Consumers because some generation eligible for Global Adjustment (solar, gas and coal) is only available during peak periods and is sold at a higher market price than the annual average.

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. This difference is referred to as the unexpected variance and will be included in the RPP supply cost for the next RPP period.

RPP consumers are not charged the average RPP supply cost (or the RPA). Rather, they pay prices under price structures that are designed to make their consumption weighted average price equal to the RPA. There are two RPP price structures, one for consumers with conventional meters (Tier Pricing) and one for consumers with eligible time-of-use (or "smart") meters who pay time-of-use (TOU) prices.

Conventional Meter Regulated Price Plan (Tier Pricing)

The conventional meter RPP has prices in two tiers, one price (referred to as $RPCMT_1$) for monthly consumption under a tier threshold and a higher price (referred to as $RPCMT_2$) for consumption over the threshold. The threshold for residential consumers changes twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30). The threshold for non-residential RPP consumers remains constant at 750 kWh per month for the entire year.

The resulting **tier prices** for consumers with conventional meters are:

- $RPCMT_1$ = **6.5** cents per kWh, and.
- $RPCMT_2$ = **7.5** cents per kWh.

Based on consumption over the 12 month period ending February 28, 2010, approximately 55% of RPP consumption was at the lower tier price ($RPCMT_1$) and 45% was at the higher tier price ($RPCMT_2$). Given this split, the weighted average price for conventional meter RPP consumption is forecast to be equal to the RPA.

UNDERTAKING

Undertaking

TO PROVIDE UPDATE TO (D) OF ENERGY PROBE IR 23

Response

D)

		Rate -$/MWh	Weighting	$/MWh
*	Forecasted Average HOEP	33.87		
**	Forecasted Average Global Adjustment	24.94		
	Forecasted Average non-RPP cost	58.81	31%	18.23
**	Forecasted Average RPP cost	62.15	69%	42.89
	Weighted Average Commodity Cost			**61.12**

Note:

* Per October 15, 2009 Ontario Wholesale Electricity Market Price Forecast (avg of May 2010 to Apr 2011 periods)

** Per October 15, 2009 Regulated Price Plan Price Report

E) The use of the above weighted average commodity cost results in a 2010 Cost of Power amount of $1,993.9M compared to the filed amount of $2,008.4M, a difference of $14.5M. This lowers the cash working capital amount and rate base by $1.5M to $299.2 and 4,834.1 respectively in 2010. This rate base reduction would result in a reduction of 2010 revenue requirement by $0.1M to $1,149.5M.

The use of the above weighted average commodity cost results in a 2011 Cost of Power amount of $1,980.0M compared to the filed amount of $1,994.6M, a difference of $14.6M. This lowers the cash working capital amount and rate base by $1.5M to $303.9 and 5,144.1 respectively in 2011. This rate base reduction would result in a reduction of 2011 revenue requirement by $0.1M to $1,263.4M.

An additional adjustment factor is required to "clear" the expected balance in the OPA variance account as of October 31, 2009. The majority of the current outstanding balance was accumulated as a result of lower than forecast electricity prices. The forecast adjustment factor to clear the existing variance balance is a credit (reduction in the RPP price) of $1.86 / MWh (0.186 cents per kWh)[4].

The resulting average RPP supply cost, or the RPA, is $62.15 / MWh (6.215 cents per kWh). This is summarized in Table ES-1.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2009)

RPP Supply Cost Summary for the period from November 1, 2009 through October 31, 2010		
Forecast Wholesale Electricity Price		$35.68
Load-Weighted Price for RPP Consumers ($ / MWh)		$38.14
Impact of the Global Adjustment ($ / MWh)	+	$24.94
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh	+	$0.94
Adjustment to Clear Existing Variance ($ / MWh)	+	($1.86)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$62.15**

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. This difference is referred to as the unexpected variance and will be included in the RPP price the following RPP term.

RPP consumers are not charged the average RPP supply cost (or the RPA). Rather, they pay prices under price structures that are designed to make their consumption weighted average price equal to the RPA. There are two RPP price structures, one for consumers with conventional meters and one for consumers with eligible time-of-use (or "smart") meters who pay time-of-use (TOU) prices.

Conventional Meter Regulated Price Plan

The conventional meter RPP has prices in two tiers, one price (referred to as $RPCMT_1$) for monthly consumption under a tier threshold and a higher price (referred to as $RPCMT_2$) for consumption over the threshold. The threshold for residential consumers changes twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30). The threshold for non-residential RPP consumers remains constant at 750 kWh per month for the entire year.

4 After October 31, 2009, Municipalities, Colleges, Universities, Schools and Hospitals (the MUSH sector consumers) will no longer be eligible for supply under the RPP. As they leave the RPP, they will receive a credit representing their share of the accumulated positive variance. This affects the variance account balance as of October 31, 2009 and has already been taken into account in the previous 12-month RPP price forecast.

The forecast cost of supply to RPP consumers under the Market Rules depends on two forecasts:

- o The forecast of the simple average hourly Ontario electricity price (HOEP) in the IESO-administered market over all hours in each month of the year; and
- o The forecast of the ratio of the load-weighted average market price paid by RPP consumers in each month to the simple average HOEP in that month.

The forecast of HOEP is taken directly from the Ontario Market Price Forecast Report. That report also contains a detailed explanation of the assumptions that underpin the forecast such as generator fuel prices (e.g., coal and natural gas). Table 1 below shows forecast seasonal on-peak, off-peak, and average prices. The prices provided in Table 1 are simple averages over all of the hours in the specified period (i.e., they are not load-weighted). These on-peak and off-peak periods differ from and should not be confused with the TOU periods associated with the RPP TOU prices discussed later in this report.

Table 1: Ontario Electricity Market Price Forecast ($ per MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average	Term Average
RPP Year	Q1	Nov 09 - Jan 10	$46.43	$29.02	$36.93	
	Q2	Feb 10 - Apr 10	$45.43	$29.53	$36.85	
	Q3	May 10 - Jul 10	$39.19	$20.63	$29.18	
	Q4	Aug 10 - Oct 10	$51.43	$30.07	$39.80	$35.68
Other	Q1	Nov 10 - Jan 11	$43.85	$25.20	$33.67	
	Q2	Feb 11 - Apr 11	$42.04	$24.99	$32.84	$33.26

33.87

Source: Navigant Consulting, *Wholesale Electricity Market Price Forecast Report*

Note: On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard Time (EST) on working weekdays and off-peak hours include all other hours.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and September 2009.

As shown in Table 1, the forecast simple average HOEP for the period November 1, 2009 to October 31, 2010, is $35.68 / MWh (3.568 cents per kWh), and the forecast of the load weighted average price for RPP consumers is $38.14 / MWh (3.814 cents per kWh).

The amount of electricity supplied under the RPP depends on which consumers are eligible to receive the RPP. Currently, consumers eligible for the RPP include residential consumers, small commercial consumers, farms, and "designated" consumers including municipalities, universities, colleges, schools, hospitals (i.e., MUSH sector), as well as any other consumers whose annual usage is 250,000 kWh or less. The Ontario government amended Regulation 95/05 in March 2008 to maintain the current RPP eligibility criteria until May 1, 2009, and the Ministry of Energy and Infrastructure amended that regulation again to further extend eligibility until November 1, 2009. At that time, MUSH sector consumers will no longer be eligible for the RPP. Residential consumers, small businesses, farms and any other consumers whose annual usage is 250,000 kWh or less will continue to be eligible.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from November 1, 2010)

RPP Supply Cost Summary for the period from November 1, 2010 through October 31, 2011		
Forecast Wholesale Electricity Price		$39.23
Load-Weighted Price for RPP Consumers ($ / MWh)		$42.16
Impact of the Global Adjustment ($ / MWh)	+	$26.38
Total Contract Cost		$72.67
Market Value		($46.29)
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	($1.16)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$68.38**

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. This difference is referred to as the unexpected variance and will be included in the RPP supply cost for the next RPP period.

RPP consumers are not charged the average RPP supply cost (or the RPA). Rather, they pay prices under price structures that are designed to make their consumption weighted average price equal to the RPA. There are two RPP price structures, one for consumers with conventional meters (Tier Pricing) and one for consumers with eligible time-of-use (or "smart") meters who pay time-of-use (TOU) prices.

Conventional Meter Regulated Price Plan (Tier Pricing)

The conventional meter RPP has prices in two tiers, one price (referred to as $RPCMT_1$) for monthly consumption under a tier threshold and a higher price (referred to as $RPCMT_2$) for consumption over the threshold. The threshold for residential consumers changes twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30). The threshold for non-residential RPP consumers remains constant at 750 kWh per month for the entire year.

The resulting **tier prices** for consumers with conventional meters are:

- $RPCMT_1$ = **6.4** cents per kWh, and.
- $RPCMT_2$ = **7.4** cents per kWh.

Based on consumption over the 12 month period ending August 31, 2010, approximately 56% of RPP consumption was at the lower tier price ($RPCMT_1$) and 44% was at the higher tier price ($RPCMT_2$). This ratio is expected to remain the same in the upcoming RPP period. Given this split, the average price for conventional meter RPP consumption is forecast to be equal to the RPA.

The forecast cost of supply to RPP consumers under the Market Rules depends on two forecasts:

- The forecast of the simple average hourly Ontario electricity price (HOEP) in the IESO-administered market over all hours in each month of the year; and
- The forecast of the ratio of the load-weighted average market price paid by RPP consumers in each month to the simple average HOEP in that month.

The forecast of HOEP is taken directly from the Market Price Forecast Report. That report also contains a detailed explanation of the assumptions that underpin the forecast such as generator fuel prices (e.g., coal and natural gas). Table 1 below shows forecast seasonal on-peak, off-peak, and average prices. The prices provided in Table 1 are simple averages over all of the hours in the specified period (i.e., they are not load-weighted). These on-peak and off-peak periods differ from and should not be confused with the TOU periods associated with the RPP TOU prices discussed later in this report.

Table 1: Ontario Electricity Market Price Forecast ($ per MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average	Term Average
RPP Year	Q1	Nov 10 - Jan 11	$51.91	$36.64	$43.59	
	Q2	Feb 11 - Apr 11	$48.79	$33.64	$40.59	
	Q3	May 11 - Jul 11	$44.52	$27.21	$35.20	
	Q4	Aug 11 - Oct 11	$47.66	$29.17	$37.57	$39.23
Other	Q1	Nov 11 - Jan 12	$46.77	$30.42	$37.87	
	Q2	Feb 12 - Apr 12	$42.27	$26.70	$33.85	$35.88

Jan to Dec
Avg
$38.28

Source: Navigant Consulting, *Wholesale Electricity Market Price Forecast Report*
Note: On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard Time (EST) on working weekdays and off-peak hours include all other hours.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and September 2010.

As shown in Table 1, the forecast simple average HOEP for the period November 1, 2010 to October 31, 2011, is $39.23 / MWh (3.923 cents per kWh). The forecast of the load weighted average price for RPP consumers ("M" in Equation 1) is $42.16 / MWh (4.216 cents per kWh), or $2.4 billion in total.

2.2.2 RPP Share of the Global Adjustment

Alpha ("α") in Equation 1 represents the share of the Global Adjustment paid (or credited to) RPP consumers. Currently, the Global Adjustment is allocated based on each consumer's energy consumption. The first step in determining alpha is therefore to estimate RPP consumers' share of total consumption. Since the RPP was introduced, some consumers have chosen to leave the RPP program to sign competitive retail supply contracts. Some RPP consumers with interval meters have also chosen to purchase power in the spot market instead of under the RPP. Some consumers have also returned to the RPP from retail contracts. The

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		5.95%											
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

STRANDED METERS

Exhibit 11, Tab 1, Schedule 1 provides detailed information on stranded meters.

The OEB has provided guidance to distributors on the recovery of stranded meter costs in its document entitled <u>G-2008-0002 *"Smart Meter Funding and Cost Recovery"*</u>*, issued October 22, 2008.*

The following was taken from the OEB document mentioned above:

> *"The Board accepted that the installation of smart meters means that older meters will be retired earlier than planned and that the costs associated with retired meters will not have been fully depreciated. Therefore, distributors would be at risk of not recovering the costs of stranded meters.*
>
> *The Board accepted that stranded costs would be recoverable. The Board's direction for the 13 authorized distributors was to leave the older meters in rate base and to continue to track the costs associated with the stranded meters. The Board deferred a decision on stranded meter costs for several reasons, but noted that distributors can if they choose bring forward applications for the recovery of stranded meter costs in their rates."*

Costs to the end of 2009 will remain in the rate base however; costs for 2010 onwards will be tracked in a variance account.

At the end of 2009, there were 115,546 stranded meters with a net book value of $2,340,641. The Company expects the number to increase to 120,256 meters by the end of 2011 at which time the estimated net book value will be $2,927,641.

COSTS ASSOCIATED WITH SMART METERING ENTITY

Hydro One Brampton has not incurred any costs to date for functions which the Smart Metering Entity (SME) has the exclusive authority pursuant to O. Reg. 393/07. However, the Company 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. The Company also expects to incur costs associated with integrating the Advanced Metering Infrastructure (AMI), the Meter Data Management/Repository

(MDM/R) as well as internal costs relating to these programs for which a new Deferral Account has been proposed

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.

have in 2011 that are eligible for each of the Ontario Apprenticeship Training Tax Credit, the Federal Apprenticeship Job Creation Tax Credit and the Cooperative Education Tax Credit?"

MR. GRIBBON: We would see similar levels to previous years.

MR. AIKEN: And that brings me to part (c):

"Please provide the Ontario Apprenticeship Training Tax Credit, the Federal Apprenticeship Job Creation Tax Credit and the Cooperative Education Tax Credit claimed on your 2009 tax return."

MR. GRIBBON: The Ontario Apprenticeship Training Tax Credit is approximately $40,000.

The Federal Apprenticeship Job Creation Tax Credit is approximately $9,000.

And the Cooperative Education Tax Credit is 14 -- approximately $15,000.

MR. AIKEN: Thank you.

Question 27 refers to OEB Interrogatory No. 36 and Energy Probe Interrogatory No. 48, part (f):

"HOBNI has not updated table 3 as requested."

So these are my questions. (a):

"Why has Hydro One Brampton assumed the debt to be issued by its parent in both 2010 and 2011 is 30-year debt?"

MR. GRIBBON: The debt is consistent with the long lives of the assets.

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.

Cost of Debt: Long Term

Hydro One Brampton is requesting a return on Long Term Debt for the 2011 Test Year of 6.76% which is the weighted average long term debt for the 2011 Test Year. **Table 2** below calculates the debt rate:

Table 2: Long Term Debt and Weighted Average Debt Rate for 2011 Test Year

Description	Issue Date	Debenture	Debt Rate	Interest on Debt
Debt through parent company public debenture issue	2001	$ 143,000,000	6.95%	$ 9,938,500
New Debt to be issued through parent in 2010	2010	$ 10,000,000	5.71%	$ 571,000
New Debt to be issued through parent in 2011	2011	$ 47,000,000	6.41%	$ 3,012,700
Totals		**$ 200,000,000**	**6.76%**	**$ 13,522,200**

All debt held by Hydro One Brampton is held by its shareholder Hydro One Inc. through external debt issuances. In the Cost of Capital Report the OEB determined "that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.

Cost of Debt: Short Term

Hydro One Brampton is requesting a return on Short Term Debt for the 2011 Test Year of 2.07% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on March 7, 2009. Hydro One Brampton understands that the OEB will be finalizing the return on short term debt for 2011 rates based on January 2011 market interest rate information. Hydro One Brampton's use of a Return on Short Term Debt of 2.07% is without prejudice to any revised ROE that may be adopted by the OEB in early 2010.

NEW LONG-TERM DEBT ASSUMPTIONS

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.

School Energy Coalition Interrogatory # 33

[Ex. 5/1/2.0]

With respect to Cost of Capital

a. P. 1. Please explain why the Applicant's ROE and short-term debt rate would not be set by this Board prior to the effective date of new rates. Please identify the latest Consensus Forecast and Government of Canada/A rated Canadian Utility index bond yields that could be used to set rates in a timely manner for January 1, 2011.

Response:

HOBNI's ROE and short-term debt rate could be set by this Board prior to the effective date of new rates on January 1, 2011 based on the September 2010 market interest rate information.

b. P. 2. Please provide the debenture documents relating to the public debenture issue referred to, including but not limited to all documents relating to the rights to redeem or repurchase prior to maturity. Please confirm that this issue included borrowing for the Applicant and for other purposes by the parent company. Assuming that to be the case, please confirm that any repayment or refinancing of the debenture have been applied pro rata to the respective uses to which it was originally put.

Response:

See **Appendix AN**

The issue referred to was for $300M of which $143M was allocated to HOBNI, the remainder was for HOI purposes. There has been no repayment or refinancing of the HOBNI debt.

c. P. 2. Please provide an update of the basis of the 6.41% forecast of 30 year debt in 2011 (e.g. a more recent version of the Consensus Forecasts). Please provide details of the timing of the expected borrowing. Please provide the current market price of such debt.

An update of the basis of the 6.41% forecast of 30 year debt and timing is provided in response in Exhibit 12, Tab 1, Schedule 36 parts (b) and (c). The current market yield for long term debt is approximately 5.0%.

Update of forecast for 30 year debt	**Bridge**	**Test**	
	2010	**2011**	**2012**
5-Year			
Government of Canada %	2.64	3.14	3.84
Hydro One Credit Spread %	0.86	0.86	0.86
Hydro One Bond Interest Rate %	3.50	4.00	4.70
10-Year			
Government of Canada %	3.40	3.90	4.60
Hydro One Credit Spread %	1.19	1.19	1.19
Hydro One Bond Interest Rate %	4.59	5.09	5.79
30-Year			
Government of Canada %	3.95	4.45	5.15
Hydro One Credit Spread %	1.49	1.49	1.49
Hydro One Bond Interest Rate %	5.44	5.94	6.64
90-Day BA Rate %	0.32	2.16	3.45

d. Please describe all steps that the Applicant has taken, if any, to determine whether it can redeem or repay the $143 million note in whole or in part. Please describe all barriers to that potential refinancing. Please provide all internal documents in the period from 2008 to date relating to repaying or refinancing that debt, and all calculations of potential future interest cost savings done by the Applicant.

Response:

There has been no repayment or refinancing of the HOBNI debt. The Note with HOI is callable by HOBNI; however, the call price is determined based upon the Government of Canada yield (for a maturity of the same term) plus 0.22%. Hydro One's debt issuance spread level is much higher than the 0.22%; hence, it is not economic for HOBNI to call and refinance this debt. To refinance the existing HOBNI debt with 3rd party debt having the same remaining term of approximately 20 years Hydro One Inc would issue new debt based upon the Government of Canada yield for a comparable maturity plus a spread of between 1.19% (10 year spread) and 1.49% (30 year spread), as shown in response to Exhibit 12, Tab 1, Schedule 36 part (c).

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.

ENBRIDGE

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North York, Ontario M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Robert Bourke
Manager, Regulatory Proceedings
Tel: 416-495-5616
Fax: 416-495-6072
Email: robert.bourke@enbridge.com

November 26, 2010

VIA COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. ("EGD" or the "Company")
Draft Rate Order – 2009 Earnings Sharing Mechanism EB-2010-0042

Pursuant to the Board's Decision and Order dated November 10, 2010, attached please find the Company's draft materials for inclusion in the Board's Final Rate Order for the 2009 Earnings and Sharing Mechanism docket EB-2010-0042.

The materials for inclusion in the Board's Final Rate Order include the following:

- Appendix "A" – A copy of Exhibit B, Tab 5, Schedule 1, originally filed in the Company's 2011 rate proceeding EB-2010-0146, dated October 1, 2010 indicating the balances and interest for accounts approved in EB-2010-0042 for clearance in January, 2011.

- Appendix "B" – Derivation of Proposed Clearance Unit Rates. The account balances will be cleared to customers as a one-time billing adjustment, shown as a separate line item, on customers' January 2011 bills.

- Appendix "C" – Correspondence received from the Canada Revenue Agency ("CRA") in response to the Company's request for a ruling (excluding the fax cover sheet).

As part of the noted settlement, the Company agreed to seek a ruling from the CRA in regard to the applicable tax rate, either GST or HST, to be applicable on the amounts to be cleared, as follows:

> Enbridge agrees to seek a ruling or other binding decision from the Canada Revenue Agency ("CRA") about whether clearance to customers of the balances in the Deferral and Variance Accounts will result in any refund of HST or reduction in HST that would

> otherwise be payable by customers. Should the CRA allow a refund of HST or a reduction in HST otherwise payable, any such HST credit will be passed through to customers, provided always that there will be no expense or outlay by Enbridge or its shareholder to fund or contribute to the HST refund or reduction.

EGD is in receipt of a faxed copy of correspondence from the CRA, dated November 25, 2010, that indicates under the heading **RULING GIVEN**, the following:

> Based on the facts set out above, we rule that as the original supply of natural gas to which the adjustment applies was made in 2009, paid as a one-time adjustment to EGDI's customers on their bills for the month of January 2011 is a reduction in consideration for the supply of natural gas by EGDI under subsection 232(2) and GST at 5% would apply to the reduction in consideration.

As a result of the Ruling Given, the one-time billing adjustment in January 2011 stemming from the clearance of the balances in question will attract the GST rate of 5.00%. The CRA correspondence is attached as Appendix C.

The draft materials for the Board's Final Rate Order have been circulated to all parties.

The Company is respectfully requesting that the Board approve and issue the Final Rate Order on or before December 10, 2010 in order that the timetable for the filing and approval January 1, 2011 QRAM and the implementation of 2011 Final Rates resulting from the EB-2010-0146 rate proceeding can be maintained.

Thank you for this consideration.

Yours truly,

Robert Bourke

Robert Bourke
Manager Regulatory Proceedings

Encl.

cc: Mr. F. D. Cass, Aird & Berlis (via courier)
EB-2010-0042 Interested Parties (via email only)

APPENDIX "C"

Correspondence received from the Canada Revenue Agency

Canada Revenue Agency / Agence du revenu du Canada

Ontario Region
LPRA Division – GST/HST Rulings
PO Box 2220
55 Bay Street North
Hamilton ON L8N 3E1

Enbridge Gas Distribution Inc.
500 Consumers Road
North York ON M2J 1P8

Case Number: 129334
Business Number: 105205140

Attention: Enzo Baldan
Manager, Tax Services

November 25, 2010

Dear Mr. Baldan:

Subject: **GST/HST RULING**
Refund of overcharges to customers

Thank you for your fax of September 24, 2010, concerning the application of the Goods and Services Tax (GST)/Harmonized Sales Tax (HST) to the refund of overcharges to customers.

HST applies at the rate of 15% in Nova Scotia, 13% in Ontario, New Brunswick, and Newfoundland and Labrador, and 12% in British Columbia. GST applies at the rate of 5% in the remaining provinces and territories.

All legislative references are to the *Excise Tax Act* (ETA) unless otherwise specified.

STATEMENT OF FACTS

We understand the following:

1. Enbridge Gas Distribution Inc. (EGDI) is in the business of natural gas distribution in Canada servicing residential, commercial and industrial customers in Toronto, Ottawa, Peel, Dufferin, York, Durham, the Niagara Peninsula, Peterborough, Barrie, Collingwood and other Ontario communities.

2. EGDI provides its customers with a continuous supply of natural gas to their premises by means of its pipeline distribution system.

3. EGDI is subject to the regulatory authority of the Ontario Energy Board (OEB), which controls the rate charged by EGDI to its customers for the distribution, transmission and storage of natural gas and the price charged for natural gas.

4. During the 2009 calendar year, the supply of natural gas was made to EGDI's customers at the OEB approved rate plus 5% GST.

5. During 2009, the OEB approved price exceeded the actual costs associated with the delivery of the taxable supply. As mandated by the OEB, EGDI is not allowed to profit from the sale and delivery of natural gas. Per OEB requirements, the difference was accumulated in approved Deferral and Variance accounts.

6. To clear the difference in the Deferral and Variance accounts, quarterly price adjustments to customer billings were made from April 1, 2009 to March 31, 2010.

7. As of April 30, 2010, the total remaining 2009 balance owed to EGDI customers amounted to $42.5 million. GST of 5% associated with this balance was collected and remitted to the Canada Revenue Agency (CRA).

8. On June 29, 2010, EGDI received an order from the OEB to refund the remaining 2009 monies ($42.5 million) owed to its customers. The refund will be reflected as a one-time adjustment on a customer's bills for the month of January 2011. This one-time adjustment will only be paid to those customers who were on record during the 2009 calendar year and will be specific to each customer, based on the actual supply of gas to that customer during 2009 (i.e., their actual gas consumption).

RULING REQUESTED

You would like to know whether the refund constitutes a reduction to the consideration of the supply of gas originally made and therefore subject to section 232 and if so, would GST at 5% or HST at 13% apply to the credit.

RULING GIVEN

Based on the facts set out above, we rule that as the original supply of natural gas to which the adjustment applies was made in 2009, the refund paid as a one-time adjustment to EGDI's customers on their bills for the month of January 2011 is a reduction in consideration for the supply of natural gas by EDGI under subsection 232(2) and GST at 5% would apply to the reduction in consideration.

This ruling is subject to the qualifications in GST/HST Memorandum 1.4, *Excise and GST/HST Rulings and Interpretations Service.* We are bound by this ruling provided that none of the above issues are currently under audit, objection, or appeal, that no future changes to the ETA, regulations or our interpretative policy affect its validity, and all relevant facts and transactions have been fully disclosed.

EXPLANATION

Under subsection 232(2), EDGI has up to four years after the end of the reporting period in which the consideration was reduced to adjust the amount of tax charged or to refund or credit the tax collected to the recipient.

There is no requirement for EDGI to refund, adjust, or credit the GST charged or collected. It is at EDGI's discretion whether the tax is refunded, adjusted or credited. However, it is expected that a refund, adjustment, or credit of the tax will usually be given in instances where the customer is a GST/HST non-registrant.

Where the customer is a GST/HST registrant, EDGI may choose not to refund, adjust or credit the GST previously charged or collected. This may be desirable where EDGI has already accounted for the tax and the customer has already claimed or is entitled to claim a corresponding input tax credit.

For additional information refer to GST/HST Memorandum 12.2, *Refund, Adjustment, or Credit of the GST/HST under Section 232 of the Excise Tax Act.*

If you require clarification with respect to any of the issues discussed in this letter, please call me directly at 905-308-8853. Should you have additional questions on the interpretation and application of GST/HST, please contact a GST/HST Rulings officer at 1-800-959-8287.

Yours truly,

M. Forte-Long

Maria Forte-Long
GST/HST Rulings Centre