Administrative (Exhibit 1)

Letters of Comment

Question OEB 1

Has London Hydro received any letters of comment following its publication of the Notice of Application and Hearing on November 14, 2012? If so, please provide a copy of the letter(s) and London Hydro's response, removing any information that would identify the author(s).

Response OEB 1

London Hydro has not received any letters of comment following our publication of the Notice and Hearing on November 14, 2012.

Consolidation of Corrections and/or Modifications to the Revenue Requirement

Question OEB 2

Upon completion of all Board staff interrogatories, please identify any responses that contain any corrections or adjustments that London Hydro wishes to make to the revenue requirement.

a) Please provide a log of each correction or adjustment
b) Please make any corrections or adjustments to the Revenue Requirement Work Form, in the middle column, leaving the first column unchanged from the application as filed.
c) Please indicate the percentage change in the base revenue requirement resulting from the corrections and adjustments, and if the change is substantial provide an updated Appendix 2-W with impacts based on recalculated rates.

Response OEB 2

a) The log of corrections or adjustments that is proposed by London Hydro in response to Board staff interrogatories is contained in Table 1: Log of Proposed Corrections or Adjustments.

The Table for the Log of Proposed Corrections or Adjustments is as follows.

Table 1: Log of Proposed Corrections and Adjustments

Topic	Description	Referenced	Base Revenue Change
Water Billing Contract	In Original Sept 25, 2012 Application London Hydro recovery for water billing services was $3,950,000. This correct amount is in fact $3,750,000, a difference of $200,000 in OM&A.	Board Staff # 35 a) Cost Recovery	$ 201,865

Propose Adjustment:

a) Referenced Q #35 and Water Billing Contract

#35. Cost Recovery

References: Exh 4, pp. 77 and 102

In Exhibit 4 the forecast cost recovery for London Hydro's water billing services provided to the City of London is described at page 77, with a forecast amount of $3,950,000. At page 102, forecast price is shown at $3,750,000, against an incremental cost of $1,030,000.

Corrected cost recovery from Water Billing Services is in fact $3,750,000 and not $3,950,000 as reflected in the original Application. OM&A proposed adjusted reflects an increase of $200,000, or base revenue change of $201,865.

b) The revised Revenue Requirement work form is included as Excel filing LondonHydro_Rev_Reqt_Work_Form_Amended_20130108. As per Board staff request, only the middle column reflects proposed corrections and adjustments.

Copy of the updated Revenue Requirement Workform (Tab 9, Revenue Requirement)

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$33,844,562	a).	$34,044,562		$34,044,562	
2	Amortization/Depreciation	$15,788,219		$15,906,200		$15,906,200	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$934,484		$934,783		$934,783	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$8,648,455		$8,634,049		$8,634,049	
	Return on Deemed Equity	$9,834,653		$9,818,270		$9,818,270	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$117,981		$32,354		$32,354	
8	**Service Revenue Requirement (before Revenues)**	$69,168,354		$69,370,218		$69,370,218	
9	Revenue Offsets	$3,397,982		$3,397,982		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$65,770,372		$65,972,236		$69,370,218	
11	Distribution revenue	$65,770,371		$65,972,236		$65,972,236	
12	Other revenue	$3,397,982		$3,397,982		$3,397,982	
13	**Total revenue**	$69,168,353		$69,370,218		$69,370,218	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	$ -	(1)	$ -	(1)

Notes
(1) Line 11 - Line 8
a). Water Billing Services recovery adjusted from $3,950,000 to corrected amount of $3,750,000, for a difference in OM&A of $200,000.

c) The percentage change in the base revenue requirement resulting from proposed corrections and adjustments as reflected in The Table for the Log of Proposed Corrections or Adjustments totals 0.3%.

As reflected in the Table the total change from proposed corrections and adjustments to the total base revenue requirement is $201,566. The total base revenue requirement originally requested in this Application was $65,770,372. Therefore, the total base revenue requirement total percentage change calculates to 0.3%.

As the percentage change in total base revenue requirement is small, the updated Appendix 2-W with impacts based on recalculated rates has not been provided in this response.

Rate Base (Exhibit 2)

Issue 2.3 Are the proposed Capital Expenditures for the 2013 Test Year appropriate?

System Performance and Reliability

Question OEB 3

References: (i) Executive Summary / 2nd page
(ii) Exh 2 / pp. 29-34

Reference (i) states the following:

> *"London Hydro's mission includes the pursuit of excellence in reliability. To this end, London Hydro has worked diligently over the last decade to raise its performance ratings from second lowest in the Province to equal with its peers."*

Reference (ii) provides graphs which show historical system performance in terms of SAIFI, SAIDI and CAIDI.

a) *What measures were undertaken by London Hydro in 2011- 2012 and planned for 2013 to maintain the existing system reliability performance or its trend towards further improvement?*

b) *Please describe the expected impact on reliability of the measures taken in 2011-2012.*

Response OEB 3

a) A key element of London Hydro's mission is to strive for continuous improvement in reliability. London Hydro carefully monitors its reliability statistics and looks for trends in system performance in an effort to identify, assess, and accordingly invest in the system to improve and maintain the standard of system reliability which London Hydro's customers have come to expect.

In 2011-2012 and planned for the year 2013, London Hydro has continued to plan for system reliability improvements through its capital spending programs. The following are several examples of these capital projects aimed at achieving this:

- London Hydro has injected its underground 1/0 AWG 27.6kV cables with silicon in order to prolong its asset life as well as improve its reliability. London Hydro views this to be a cost effective means to rehabilitate its aging population of underground cables as prescribed in the Asset Sustainment Plan. *(refer to 12B1, 12B2, 13B1, 13B2 for 2012 and 2013 planned work)*
- Premature failure of air insulated switchgear *(refer to 12B3, 13B3 for 2012 and 2013 planned work)*, and pole structures susceptible to pole fires *(refer to 12G2, 13G2 for 2012 and 2013 planned work)* are examples of trends or system deficiencies that

adversely affected the overall reliability of the system. Through prudent capital investment, London Hydro has and continues to mitigate these performance issues.

- Replaced numerous depreciated substation primary switches (T1-L switches), which pose a potential risk to the system's reliability and operation as it is part of primary sections of the network. *(refer to 11A2, 12A1)*
- Developed a long-term plan to replace the depreciated distribution plant energized at 4.16kV. The first phases of this work have already been completed in 2012 and more is planned for 2013. In addition to many of the benefits attributed to converting depreciated 4.16kV infrastructure to the common 27.6kV supply, the replacement of these depreciated systems will play a part in improving system reliability by reducing the risk of aged equipment failures. *(refer to 12B9, 12G3, 12G4, 13B9, 13G3, 13G5 for planned work)*
- Deployed system automation to restore power promptly and safely. As a result of targeted planning efforts *(highly automated distribution system; examples; installation of recloser and automated switches, refer to 11H3, 12H1, 13H1)* and enhanced operational capabilities (*Outage Management System*) the response time and visibility into the real time status of the network has and will continue to improve. Prompt restoration response time is critical to maintaining a high standard of system reliability.
- Converted radial underground systems by adding system loops. London Hydro had experienced a number of faults in its residential subdivisions that were serviced approximately 30 years ago with a radial configuration. These radial designs leave London Hydro staff with little option to restore power effectively and promptly; this leads to extended outage and poor system reliability. These system loops allow for operational flexibility which essentially reduces outage durations (SAIDI). Other underground system enhancements to reduce reliability risks are planned for 2013; namely the installation of sectionalizing equipment in the original 27.6kV downtown feed. This will allow the network to be sectionalized in the event of isolated faults. *(refer to 12A4, 13A3 for planned work)*
- London Hydro conducts annual "worst performing circuit" analysis. Other direct measures geared towards improving the reliability of underperforming circuits are planned annually. Based on internal reliability performance indicators, which benchmark and rank a circuit's performance, the worst performing circuits are audited and appropriate measures are taken to improve its reliability. *(refer to 13G4 for planned work in 2013)*

- London Hydro conducted civil engineering assessments of its underground structural system. In early 2012, London Hydro engaged a civil engineering professional consultant to conduct a comprehensive audit of its underground structural system. Any failure in these structures can interrupt the continuity of power supply to customers for extended periods of time, and hence adversely affecting the system reliability. Upon completion of this audit and submission of the report, London Hydro will continue to plan for the sustainment of these assets accordingly.

The capital projects referenced above are listed in detail under Exhibit 2, Appendix 2B of the 2013 COS rate application.

b) As assets depreciate and approach the end of their useful life cycle, the risk of failure increases. To offset this risk, in 2011 London Hydro created an Asset Sustainment Plan (ASP), which consolidates a number of internal engineering reports and identifies a replacement/refurbishment rate for each of London Hydro's major asset groups. The proposed asset replacement rate is designed such that depreciated assets, that put system reliability in jeopardy, are replaced in a timely manner. In this way, London Hydro ensures that it continues to meet its reliability goals into the future.

London Hydro's system reliability trends have been improving over the last decade. Although it does fluctuate from year to year the trend indicates improvement. London Hydro understands that improvements to system reliability are based on a combination of replacement of depreciated assets, targeting poor performing areas in the system based on ongoing audits and trend analysis, as well as improved operational capabilities.

London Hydro expects the work performed in 2011 and 2012 to continue to result in the same trend for improved SAIDI/SAIFI results, barring any unforeseen environmental events such as tornado, wind storm or ice storm.

Infrastructure – Subdivision rebuilds

Question OEB 4

Reference: Exh 2 / p. 55

Based on the Table in the reference, the annual capital spending on subdivision rebuilds averaged about $2.7 million per year for the period 2007-2010 and this amount increases to about $6 million per year for the period 2011-2013. The highest cost item shown is silicone injection of underground cable.

a) *Please explain why capital spending on subdivision rebuilds continues to be significantly higher (more than double) in 2012 and 2013 than the historical 2007-2010 values.*

b) *Please provide examples of other Canadian utilities that utilize silicone injection for refurbishment of underground cable and comment on its effectiveness and success in prolonging the life of underground cable.*

Response OEB 4

a) Capital spending associated with subdivision rebuilds has increased as a result of introducing silicone injection technology in 2010. As mentioned in Exhibit 2, this technology increases the lifespan of polymeric cable, adding up to another 40 years of service.

The rationale for the capital spending on subdivision rebuilds is supplied in the Asset Sustainment Plan submitted as Appendix 2C of Exhibit 2 and involves the application of a condition based assessment of the cable assets as outlined in section 2 of the Plan. The assessment incorporates a review of: safety, performance, operability, outage risk, and the environment. This type of assessment has allowed London Hydro to maximize the service life of these assets and minimize replacement costs.

In 2011, the evaluation process indicated that it was time to increase the level of expenditure associated with these assets. London Hydro will need to replace approximately 720 km of cable over the next 15 years. In a continuous effort to reduce replacement costs, London Hydro selected silicone injection over replacement as it is estimated to be one-third to one-half of the cost. This approach will allow London Hydro to maximize the impact of the capital dollars on the safety and reliability of the underground system.

b) Silicone injection technology was used with great success by North York Hydro throughout the 1990's to rejuvenate old power cable at a fraction of the cost of cable replacement.

Based on North York Hydro's success, London Hydro subsequently executed a project involving approximately 6 km in 2002. The area selected was experiencing a high

number of failures prior to injection and has not experienced any failures since then. As a result of this success, London Hydro embarked on a second project involving 10 km of cable in 2010. London Hydro has realized the advantages and effectiveness of silicone injection versus replacement. The benefits include less disruption to the customer, cost savings, and ease of implementation. The subdivisions were chosen based on a performance risk analysis; once injection was started, the cable failures were no longer experienced.

Other utilities in Ontario that have used silicone injection include: Powerstream, Brampton Hydro One, Niagara On The Lake, PUC Distribution, Veridian Connections, Hydro Ottawa and Toronto Hydro.

Infrastructure – City Works

Question OEB 5

Reference: Exh 2 / p. 63

Based on the Table in the reference, the annual capital spending on city works averaged about $513,000 per year for the period 2007-2011 and this amount increases to about $1 million per year for the period 2012-2013.

a) *Please explain why capital spending on city works is estimated to be significantly higher in 2012 and 2013 (almost double) than the historical in 2007 to 2011 values.*

b) *Are these higher levels of spending expected to continue beyond 2013? Please explain.*

Response OEB 5

a) The work undertaken by London Hydro in this area is totally dependent on requests by the road authority. As a result of road works, London Hydro is required to relocate significant overhead and underground distribution plant as per regulatory obligations under the Public Service Works on Highway Act (R.S.O. 1990 CHAPTER P.49). London Hydro can recover a portion of the labour and equipment expense involved in this work pursuant to the previously mentioned Act.

Capital spending in this area is higher than the previous years because the City of London has scheduled a higher than average number of renewal and major road widening projects for 2012 and 2013. These large projects are a result of the City of London's attempt to aggressively pursue and respond to new development. The projects completed during 2012 as identified by the City of London were in fact large in scope and spending. Please refer to the Detailed Project Description Sheets for projects

12D1 and 13D1, within the Asset Management Plan submitted as Appendix 2B of Exhibit 2, for the list of projects.

b) The City of London is aggressively pursuing major planning initiatives. As such, London Hydro believes that it is prudent to include these cost estimates beyond 2013, and has therefore made allowance for the potential for continued road redevelopments in the 2014 and 2015 capital spending forecasts.

Infrastructure – Subdivision rebuilds

Question OEB 6

Reference: Exh 2 / p. 72

Based on the Table in the reference, the estimated annual capital spending on overhead line works in 2013 is about $5.4 million which is 49% higher than 2012 and significantly higher than previous years.

a) Please explain why capital spending on overhead line works in 2013 is significantly higher than 2012 and previous years.

b) What is London Hydro's outlook for overhead line works capital spending in 2014? Please explain.

Response OEB 6

a) Capital spending in this area forecasted for 2013 is higher than previous years because London Hydro is reallocating its overhead line work efforts to address the requirements outlined in the Detail Project Description Sheet for Project 13G5, within the Asset Management Plan submitted as Appendix 2B of Exhibit 2. The proposed 2013 Test Year budget for Zone A rebuild replaces depreciated infrastructure, meeting the criteria outlined in the Asset Sustainment Plan, 2012 - 2026 Report.

The increased scope and spending outlined in project 13G5 of the Asset Management Plan is partially offset by the decreased scope in other capital budget sections. For example, the budget for 2013 for Rebuild of Fully Depreciated Overhead Areas was reduced to accommodate the larger scope of the 4.16kV program.

In general, London Hydro can only dispatch a fixed amount of overhead resources to install or maintain overhead assets in any given period due to logistical and practical implications. As a result, capital spending will vary among the parts of the budget that require overhead resources based on the needs of the system.

Practical and logistical items must be taken into consideration when developing budgets. For example, in any given year, if considerable overhead work is also being budgeted in Main Feeders or in City and Developer budgets, the overhead replacement programs may need to be reduced to accommodate resources in this area.

As a whole, the spending for 2007 and 2008 for Overhead Line Works was considerably less than the years to follow. The spending for this area was offset with spending in Main Feeders and City and Developer Works. In these two years, there was significant investment in new feeder builds in conjunction with the Hydro One upgrade of the Talbot Transformer Station to support additional capacity and increasing operating flexibility. Several new feeders were also built in the east end of the City to support new load growth.

b) London Hydro's outlook for overhead line works capital spending in 2014 is similar to that in 2013. In 2014, London Hydro will complete the final year of the three year rebuild program for Zone 'A' as outlined in the Detail Project Description Sheet for Project 13G5 within the Asset Management Plan submitted as Appendix 2B of Exhibit 2. The 4.16kV plan identified three zones that were the highest priority within the initial 10 years of the 25 year planning horizon. Work will continue on the other priority zones following the completion of Zone A. The increased expenditure in this area will continue to be partially offset by reducing spending in other areas of the capital budget.

Information Systems

Question OEB 7

Reference: Exh 2 / p. 99

Based on the table in the reference, the annual capital spending on information systems averaged about $3.7 million per year for the period 2007-2011 and this amount increases to about $5.9 million per year for the period 2011-2013, an increase of almost 60%.

The largest component of expected capital spending in information systems in 2013 is Application Development with an expected expenditure of about $4.8 million in 2013.

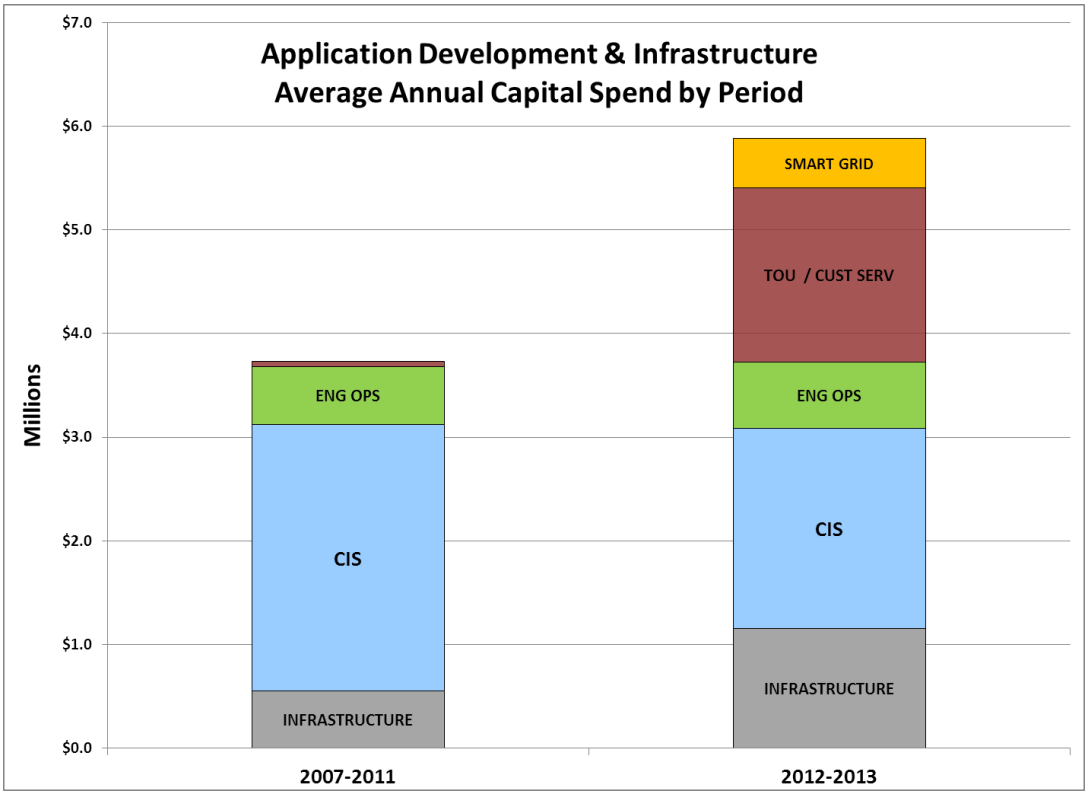
a) *Please explain the significant increase (about 59% higher) in capital spending on information systems in 2012 and 2013 compared to prior years.*

b) *Please provide a breakdown of the 2009 - 2013 capital spending on information systems according to labour, material and overheads.*

c) *Are the higher Application Development costs of 2012 and 2013 expected to continue in 2014 and beyond? Please explain.*

Response OEB 7

a) The chart below has been provided as an aide to understanding the trend of increasing expenditures in the Application Development and Infrastructure areas by grouping the various Information System projects into 5 major categories. The bullets following this chart discuss each of these major categories to further augment the understanding of the increase in average capital spending from that in 2007 to 2011 in comparison to 2012 and 2013.



Infrastructure

- Growth in data and new systems in all business areas requires a larger, more complex asset base (hardware, software, security) which needs to be sustained and upgraded as required. An illustration of the growth in data is provided in Exhibit 2, page 107 and 108, Figures 0-6 and 0-7. As an example, there have been and will continue to be investments in servers and storage, data security / backup solutions and network development

Customer Information System (CIS)

- Although lower, post-implementation costs are required to stay current with high availability and reliability (e.g. applying support / enhancement packs to address break-fix and functionality gaps to stay within vendor supported versions)

Engineering and Operations

- Continued enhancements / upgrades to the Geographic Information System (GIS) to provide more informative and accurate on-line maps
- Increased capability and tools to allow Operations to reduce customer restoration times and provide better communications with internal / external stakeholders during outages

TOU/Customer Service

- Post Smart Meter implementation to sustain Time of Use (TOU) including upgrading MDMR interfaces, compliance with Measurement Canada regulations and end-to-end integration testing from meter to case for 24 hour interval data instead of monthly register read
- Deploy customer engagement solutions such as TOU web presentments to help customers shift demand and reduce consumption
- Enhance customer communication and interaction during planned and unplanned outages (e.g. avoid busy signal on phone lines during snow storm)

Smart Grid Platform

- Initial investment to allow field staff to access near real-time information based on smart devices to reduce outage windows by improving productivity and enhancing safety
- Implement Smart Meter analytics to promote conservation and leverage the Smart Meters investment such as alarm management and pro-active reliability analysis

A listing of the projects included in each major category has been provided below for your reference.

INFORMATION SYSTEMS AVERAGE ANNUAL SPENDING BY MAJOR PROJECT CATEGORY				
	2007-2011 Actuals Average	2012 Bridge	2013 Test	**2012 Bridge and 2013 Test Average**
Smart Grid Plantform				
Mobile Workforce Management (MWFM)	-	-	450,000	225,000
Business Intelligence / Reporting	-	-	500,000	250,000
	-	-	950,000	475,000
Time of Use (TOU) / Customer Service				
MDUS / ODS (Operational Data Storage)	-	370,000	-	185,000
MDMR Interface	-	248,000	-	124,000
Measurement Canada Modifications	-	250,000	-	125,000
Customer Engagement / Self Service	30,717	500,000	500,000	500,000
IVR System Enhancement and Upgrade	19,022	-	-	-
Outage Management System (OMS)	-		1,500,000	750,000
	49,739	1,368,000	2,000,000	1,684,000
Engineering and Operations				
Geographic Information System (GIS)	438,682	480,000	-	240,000
Other (accounting, payroll, doc management)	25,033	-	-	-
Outage Management System (OMS foundation)	90,481	800,000	-	400,000
	554,195	1,280,000	-	640,000
Customer Information System (CIS)				
Customer Information System (CIS)	2,410,494	840,000	835,000	837,500
CIS EBT Optimization	123,701	580,000	-	290,000
CIS Regulatory Requirements	42,208	600,000	480,000	540,000
CIS Customer Relations Management Upgrade	-	-	525,000	262,500
	2,576,403	2,020,000	1,840,000	1,930,000
Infrastructure				
Hardware and Software	547,701	1,100,000	1,210,000	1,155,000
	3,728,039	**5,768,000**	**6,000,000**	**5,884,000**

b) A breakdown of capital spending for 2009 actuals to the 2013 Test Year has been provided below as requested, along with the internal versus external resource mix:

Category	2009 Actual		2010 Actual		2011 Actual		2012 Bridge Year		2013 Test Year	
External labour	2,637,574	80%	2,533,158	89%	2,432,717	82%	3,171,000	69%	2,787,000	61%
Internal labour	374,216		182,771		326,003		884,000		1,101,000	
Benefit overhead	270,780		115,400		205,619		563,000		702,000	
	644,996	20%	298,171	11%	531,622	18%	1,447,000	31%	1,803,000	39%
Total labour	3,282,570	100%	2,831,329	100%	2,964,339	100%	4,618,000	100%	4,590,000	100%
Acquisitions	320,382		553,826		946,412		1,150,000		1,410,000	
	3,602,952		3,385,155		3,910,751		5,768,000		6,000,000	

c) London Hydro's outlook for Information Systems capital spending for 2014 and beyond is similar to that in 2013. The anticipated costs in technology investments for 2014 and beyond are expected to continue in order to sustain and evolve London Hydro's systems and networks to accommodate growing customer demand, increasing need for Cyber Security and to be ready for Smart Grid advancements.

Issue 2.4 Is the proposed Green Energy Act Basic Plan appropriate?

Distributed Generation

Question OEB 8

Reference: Appendix 2G – Green Energy Act Plan / p. 4

Table 1 in the above-noted Reference indicates that there are a total of 104 outstanding Micro-generation projects (<10kW) with a total capacity of 891 kW. Board staff wishes to get additional information on the status and expected connection dates for these generators.

a) For the outstanding Micro-generation projects please indicate:

i. number and total kW of those already connected;

ii. number and total kW of those that have received an offer to connect;

iii. number and total kW of those that have not yet been approved.

b) b)For the projects in categories (ii) and (iii) above, please indicate:

i. number and total kW of projects expected to be connected in 2012;

ii. number and total kW of projects expected to be connected in 2013;

iii. number and total kW of projects expected to be connected beyond 2013.

Response OEB 8

Table 1 of Appendix 2G – [Green Energy Act Plan on page 4] lists the number of outstanding microFIT 1.0 applications submitted to the OPA for London Hydro's territory as of end of June 2012 - the time the GEA plan was originally submitted. Since July 2012 the OPA has re-opened the microFIT program under version 2.0. The new rules allow previous participants to re-apply

within a transition window after which all version 1.0 projects without a contract will be terminated. The OPA continues to terminate microFIT 1.0 contracts as their time limits expire. The status of Micro-generation as of December 18, 2012 is listed in the table below:

Status	Number	kW total
(a)(i) Connected (OPA status - contract accepted)	10	90kW
(a)(ii) Offer to Connect (OPA status – LDC has issued Offer to Connect)	7	62kW
(a)(iii) Submitted (OPA status – submitted)	10	94kW
(b)(i) Future connections 2012 (OPA status – LDC has issued Offer to Connect)	7	62kW
(b)(ii) Predicted future connections 2013*	30	260kW
(b)(iii) Predicted future connections beyond 2013*	30+/year	260kW+

*these numbers are assuming that the OPA's province wide procurement limit of 50MW has not been reached

Question OEB 9

Reference: Appendix 2G – Green Energy Act Plan / p. 4

Table 2 of the above-noted reference provides information regarding small, mid-sized and large distributed generation projects. Board staff wishes to get additional information on the status and expected connection dates for these generators.

a) Please provide a list of projects listed in Table 2 that are not already in service.

b) For each of these projects please provide the total kW and expected connection date.

Response OEB 9

Please see Appendix A for a listing of projects that are not already in service as of December 14, 2012. The list included in the Appendix contains all of the requests for connection information. During the first round of FIT 1.0, 18 projects were released by the OPA. Of these, 10 have been connected and three have not approached the LDC as of yet. The table below lists the remaining 5 outstanding projects and their expected connection date and kW size.

Location	Expected In-Service Date	kW size
1020 Wonderland Rd S	Early 2013	150kW
665 Adelaide St N	Early 2013	150kW
25 Cuddy Blvd	Early 2013	200kW
15825 Robin's Hill Rd	Early 2013	100kW
15790 Robin's Hill Rd	Early 2013	250kW

Challenges Associated Incorporating Distributed Generation in Urban Utility

Question OEB 10

Reference: Appendix 2G – Green Energy Act Plan / pp. 6-7

Under Section 3.1 - Operating Flexibility, it is stated that "Currently, the main restriction to re-configuring the system when it involves generation is the inability to move generation onto a different TS due to short circuit capability at Hydro One owned transformer stations. Protection modification and studies would also be required to move the generator. Correcting this situation has the potential to cost millions of dollars."

Please describe what action London Hydro has taken and/or plans to take and expected timeframe and costs to address the above-noted restriction.

Response OEB 10

An impediment to moving generation is the short circuit capabilities at the Hydro One transformer stations. These transformer stations are owned by Hydro One and as such are not within London Hydro's rate base. Therefore any such work to mitigate the short circuit restrictions at existing transformer stations lies with Hydro One, the transmitter. London Hydro has lobbied Hydro One to upgrade fault current capability of its 27.6kV stations. The lobbying efforts have had some success as Hydro One has completed an upgrade to the Clarke transformer station. As a result, the short-circuit constraint has been removed and for the present, renewable generation projects can be connected to feeders supplied from Clarke TS. London Hydro continues to lobby Hydro One to upgrade other constrained transformer stations so that all Londoners are able to take advantage of the benefit of green energy.

If London Hydro is unable to convince Hydro One to upgrade constrained transformer stations, London Hydro might have to seek to build a future Smart Grid enabled, renewable generation connection capable, 27.6kV transformer station that, in addition to supporting existing and new load, would significantly extend the areas within London to accept new generation. If London

Hydro were to seek the building of a new 27.6kV transformer station London Hydro would first seek the required approval by the OEB.

To clarify, London Hydro has not made any requests in its 2013 Cost of Service rate application for any application or funding for the suggested transformer station.

Question OEB 11

Reference: Appendix 2G – Green Energy Act Plan / p. 7

Under Section 3.2 - Protection Equipment, it is stated that "As the amount of connected generation on a feeder increases beyond 50% of the feeder minimum load, additional protection equipment is required."

> *Please describe what action London Hydro has taken and/or plans to take and expected timeframe and costs to address the above-noted issue of additional protection equipment needed due to increasing connected generation.*

Response OEB 11

The installation of additional protection equipment is not triggered until there is an actual project that would put the amount of generation over the 50% limit. This work involves modifications to the protection relays that are owned by Hydro One. These relays are located in Hydro One's transformer stations. The cost of the modification to the transmitter owned asset is borne by the generator. London Hydro has worked with Hydro One and a 2.8MW generator in 2011 to implement modifications at Buchanan TS. There were no cost implications to London Hydro.

Question OEB 12

Reference: Appendix 2G – Green Energy Act Plan / p. 7

Section 3.3 describes some overcurrent protection considerations including the need to differentiate between reverse current flow and normal current flow in systems with distributed generation and the desensitizing of transformer station relays due to multiple current sources.

Please describe what action London Hydro has taken and/or plans to take and expected timeframe and costs to address the above-noted issues associated with overcurrent protection.

Response OEB 12

Again, similar to the response in item # 11 above, no action is taken until there is an actual need to replace the relays at the Hydro One owned transformer stations due to the amount of reverse current as a result of distributed generation. The cost of the modification to the transmitter owned asset would be incurred solely by the generator.

Question OEB 13

Reference: Appendix 2G – Green Energy Act Plan / pp. 7-8

Sections 3.3 and 3.4 deal with Fault Location techniques and Worker Protection. It is indicated that fault location would become more difficult with multiple sources feeding into a fault. Also worker protection becomes more challenging since it is necessary to ensure that all potential sources are isolated before crews can work on a particular section of line.

Please describe what action London Hydro has taken and/or plans to take and expected timeframe and costs to address the above-noted issues associated distributed generation.

Response OEB 13

At this point the LDC is not aware of any practical solution to the generators providing backflow current through the LDC's fault circuit indicators. No additional action or cost is foreseen within the horizon of the GEA plan.

Each generator that is located within a crew's work zone will be visibly isolated for the protection of London Hydro's workers. Isolation costs will vary depending on the number of generators within the work zone; again no significant capital costs are foreseen.

Requirements of a Basic Plan

Question OEB 14

Reference: Appendix 2G – Green Energy Act Plan / pp. 9-10

Section 4.3.2 states that there are four transformer station buses that cannot accept any generation due to short circuit capacity. It is also stated that there are two feeders that have restrictions due to the amount of existing generation on a single feeder.

Please describe what action London Hydro has taken and/or plans to take, and the expected timeframe and costs, to address restrictions due to:

(i) station short circuit capacity, and

(ii) existing generation on feeders.

Response OEB 14

As stated earlier in item #10 the solution rests with the transmitter since London Hydro does not own those assets. London Hydro has lobbied Hydro One to have these stations upgraded. As mentioned, the efforts have resulted in the upgrade of one transformer station (not one of the four mentioned).

The two feeders in question have reached their capacity and therefore any additional generation requiring connection in these areas would require construction of additional feeder infrastructure.

Question OEB 15

Reference: Appendix 2G – Green Energy Act Plan / p. 10

Section 4.3.4 describes London Hydro's downtown network of 94 network transformers fed by 5 separate primary feeders with special protection requirements to ensure safety and reliability that can restrict the amount of generation in order to avoid reverse current flow in a transformer(s).

> *Please describe what action London Hydro has taken and/or plans to take and expected timeframe and costs to address generation restrictions and special protection requirements described above.*

Response OEB 15

At such time as London Hydro receives an application for the installation of renewable generation in the downtown area, it will perform a Connection Impact Assessment (CIA) on a generation application to determine its impact on the network. To date (and into the foreseeable future) there have been no significant requests that have materialized into a CIA and/or necessitated a review of the configuration of the network system. As mentioned above, if in the future London Hydro did apply and obtained Board approval for a new 27.6kV transformer station supplying downtown core, circuits from this transformer station will help mitigate this restriction.

Planned Development of the System

Question OEB 16

Reference: Appendix 2G – Green Energy Act Plan / pp. 10-11

Section 5.2 states that "London Hydro does not foresee any required expenditures over the next five years to accommodate renewable generation unless a project comes forward that requires an expansion or voltage upgrade."

a) *Please explain/clarify the above statement in light of the issues, restrictions etc. described in the section entitled "Challenges Associated Incorporating Distributed Generation in Urban Utility" and the preambles to Interrogatories #10-15 above.*

b) *Can the issues/restrictions identified be resolved without expenditure for the estimated number of generators and total MW (45 new projects with a total of over 8MW) over the next five years? Please explain.*

Response OEB 16

a) London Hydro anticipates that all future generation connections can be accommodated through system expansion and voltage upgrades if the Hydro One transformer station can accept generation as stated in previous answers.

b) Each new generation connection requires a Connection Impact Assessment (CIA), at that time any voltage upgrades or system expansions will be assessed.

Operating Revenue (Exhibit 3)

Issue 3.1 Are the proposed customers/connections, and proposed methodology for energy forecast and billing demand forecasts for the 2013 Test Year appropriate?

Distribution Revenues by Customer Class

Question OEB 17

Reference: Exh 3 / p. 8 / Table 3-3

In Table 3-3, London Hydro provides a summary of the number of customers / connections, consumption (kWh) or demand (kW), distribution revenues, and unit revenues ($/kWh or $/kW), by class, for 2009 Board-approved, 2009 to 2011 actuals and the forecasted amount for the 2012 bridge and 2013 test years.

a) Please confirm that the customer and connection counts represent annual averages. In the alternative, please explain.

b) Please confirm that consumption and demand figures represent annual totals. In the alternative, please explain.

Response OEB 17

a) Yes, the customer and connection counts in Table 3-3 represent annual averages. *Ref. Exh 3 / p. 10 / lines 47-18.*

b) Yes, the consumption and demand figures in Table 3-3 represent annual totals.

Question OEB 18

Reference: Exh 3, p. 8 / Table 3-3

There appear to be some anomalies in the data in Table 3-3 with respect to consumption/demand and revenues, particularly for demand-billed customer classes. As an example, the Large Use class has 3 customers for both 2009 Board-approved and for 2009 actuals. The 2009 actual demand is 392,524 kW, higher than the 2009 Board-approved demand of 383,763 kW. However, the 2009 actual distribution revenues is shown as $927,644, significantly lower than the $1,370,000 2009 Board-approved and also lower than the actual and forecasted revenues for 2010 actual to 2013 test years. Other classes (GS 50-4999 kW, Streetlighting, Sentinel Lighting, and Unmetered Scattered Loads) show similar anomalous patterns in the 2009 actual distribution revenues.

Please confirm the data shown in Table 3-3 and provide an explanation for the observed dip in 2009 actual revenues for these classes.

Response OEB 18

Comparative 2009 Board approved to actual revenues were affected by London Hydro voluntarily accepting an OEB Board offer to delay our 2009 Cost of Service (EB-2008-0235) rate application proceedings. The result was that the 2009 Cost of Service Rate Order was not issued by the Board until September 22, 2009. In the Rate Order the rates were effective September 1, 2009, but implemented on October 1, 2009.

The result of the 2009 approved rates not being implemented on May 1, 2009 but rather the approved rates being implemented as of Oct 1, 2009 was that new rates impacted revenues billed to customers for only three months in 2009. The Board approved revenue comparisons in fact reflects a full year's revenue amount. Much of the resulting variance is London Hydro's acceptance to delay the rate application proceedings in which permitted an October 1, 2009 implementation date for approved rates.

The identification of this matter is referenced in the Application under *Ref. Exh 3 / p. 5*

COMPARISON OF 2009 ACTUAL TO 2009 BOARD APPROVED:

The 2009 Actual revenues were 6.7% lower than Board Approved revenues.

2009 Board Approved rates were implemented on Oct 1, 2009 and the 2009 Board Approved revenues reflect the application of those rates for a full 12 month time frame. Actual calendar year 2009 revenues presented above reflect revenues at 2008 rates for the first nine months of 2009 and 2009 rates for the remaining three months of 2009.

*2009 rates increased by an average of 12% and revenues from those increased rates not reflected in the first nine months actual results for 2009 are approximately 9/12 *12% = 9%. The revenue variance of -6.7% is primarily due to the implementation date of the 2009 Board Approved rates.*

In addition to the above, the 2009 Actual Customer/Connection counts and quantities were significantly less than the 2009 Board Approved, and thus contributed to lower actual distribution revenues for 2009 as compared to the Board Approved Revenues.

Table: Billing Determinants by Class (2009 Board Approved Compared to 2009 Actual)

	2009 Board Approved	2009 Actual	Change from 2009 Board Approved to 2009 Actual Year	Change from 2009 Board Approved to 2009 Actual - %
BILLING DETERMINANTS BY CLASS				
Customer/Connections	182,388	178,177	-4,211	-2.3%
kWh	3,431,680,138	3,146,740,539	-284,939,599	-8.3%
kW from applicable classes	4,745,740	4,347,021	-398,719	-8.4%

Load Forecast

Question OEB 19

Reference: Exh 3 / pp. 16-17
On page 17 of the Exhibit, London Hydro provides a graph showing the actual and predicted annual results and states:

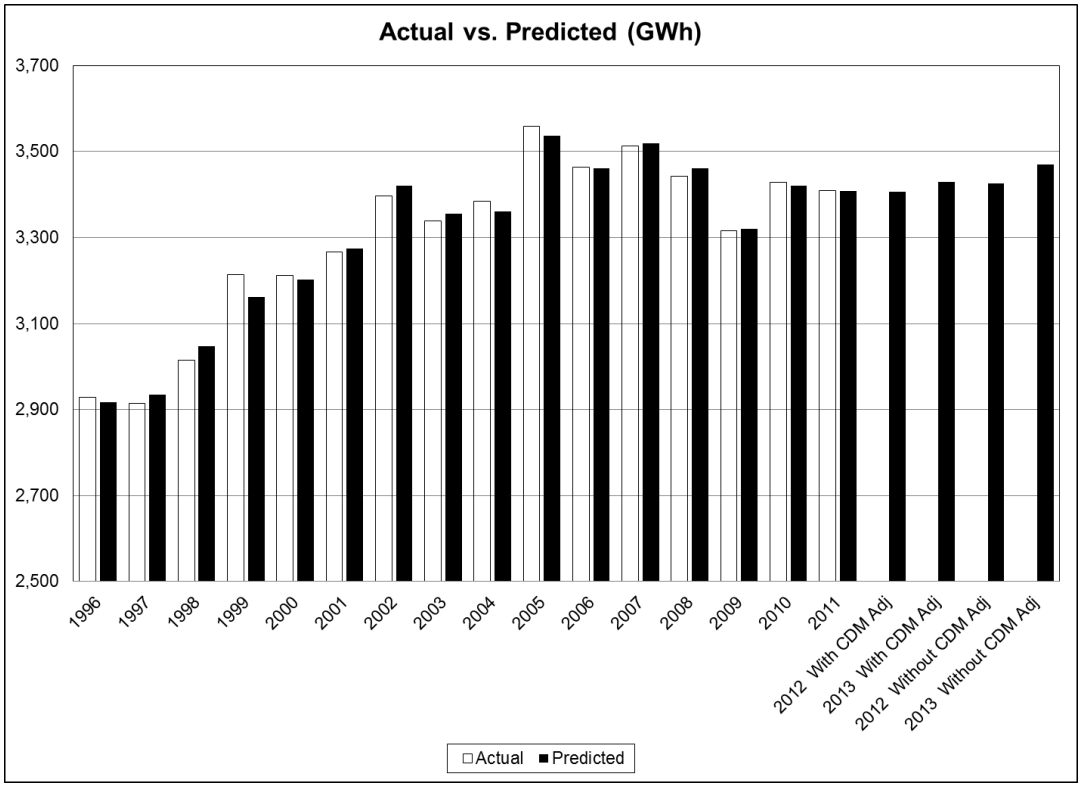
> *"The annual results of the above prediction formula compared to the actual annual purchases from 1996 to 2011 are shown in the chart .... The chart indicates the resulting prediction equation appears to be reasonable."*

The regression model is estimated using monthly data. The prediction error on an annual basis will lower the estimate of the absolute residual error, as forecasting errors in monthly results will be smoothed through monthly aggregation.

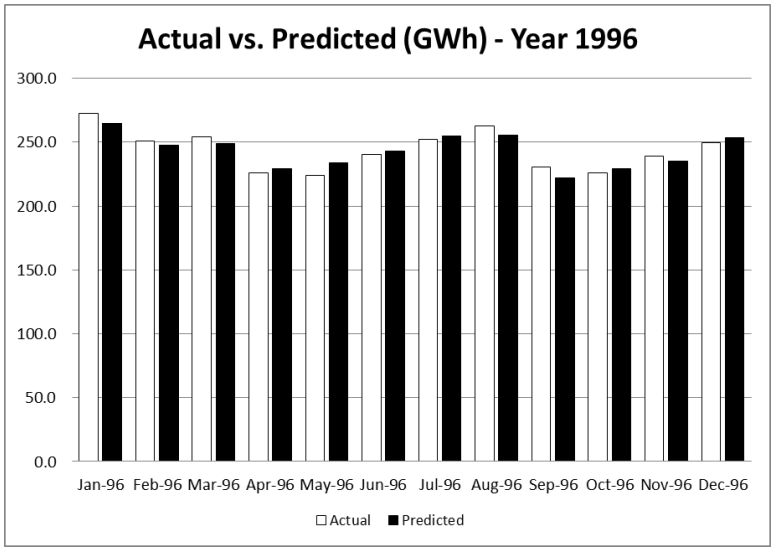
a) *Please expand the graph on page 17 to include the forecasted values for 2012 and 2013 bridge years, with and without the manual adjustments for the impacts of 2012 and 2013 CDM programs.*
b) *Please a graph similar that that shown on page 17 of the exhibit but showing the monthly actual and predicted values.*
c) *Please provide the mean average absolute error of the regression equation based on the monthly forecasted values.*

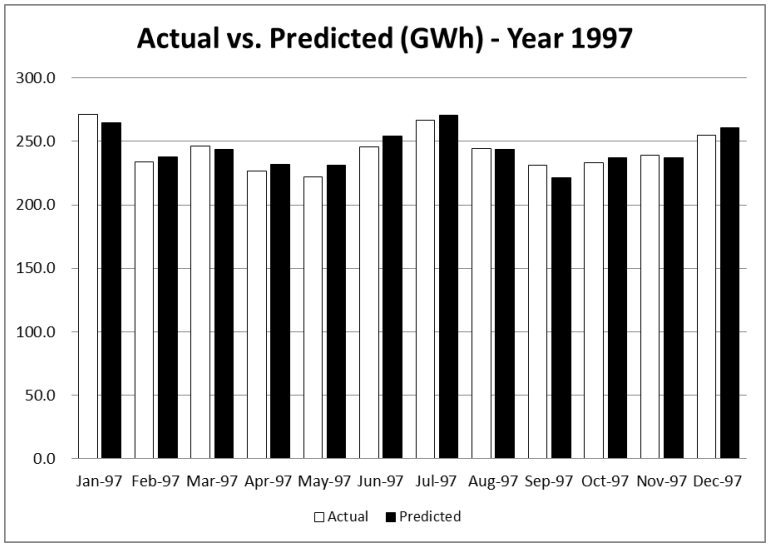
Response OEB 19

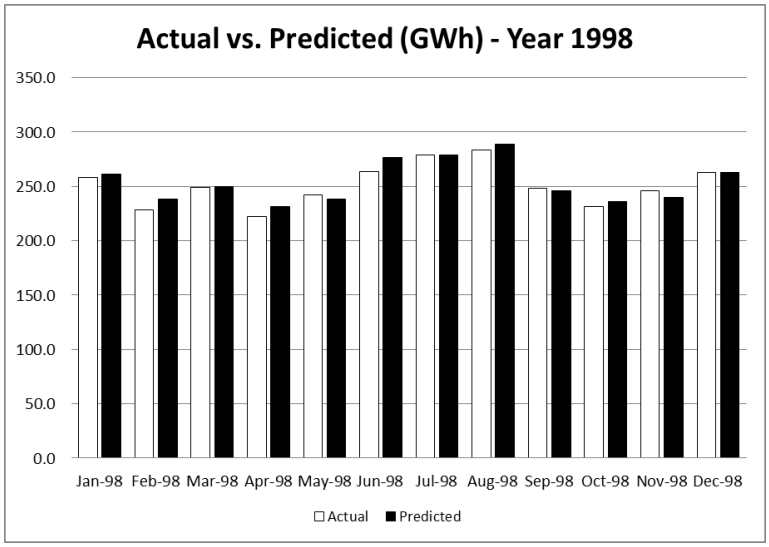
a) The graph on page 17 has been expanded to include the forecasted values for 2012 and 2013, with and without the manual adjustments for the impacts of 2012 and 2013 CDM programs. The expanded graph is provided below.

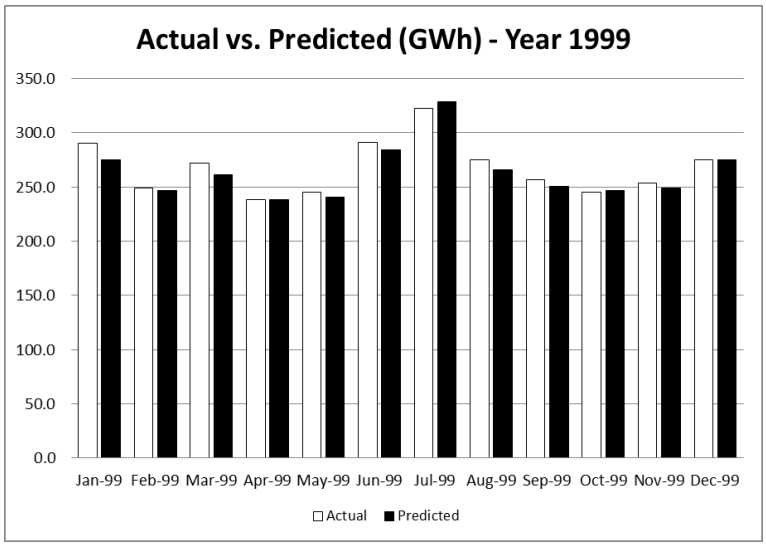


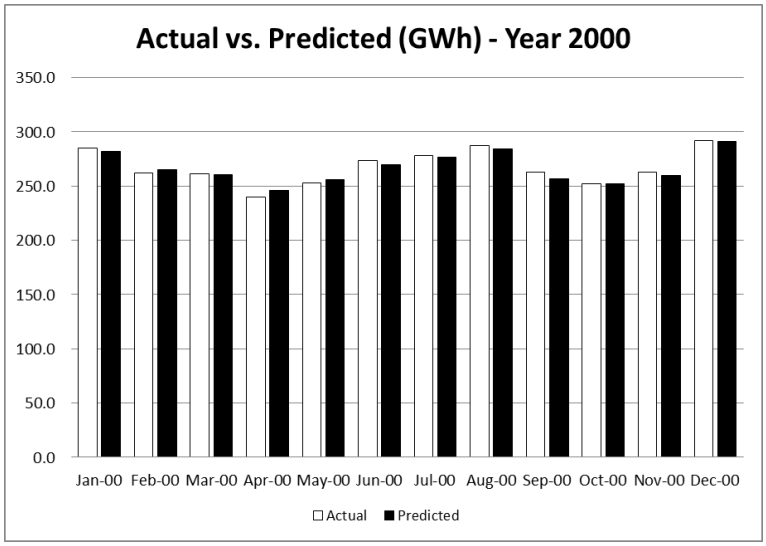
b) A graph similar to that shown on page 17 of the Exhibit but showing the monthly actual and predicted values is provided below separately for each year 1996 to 2011.

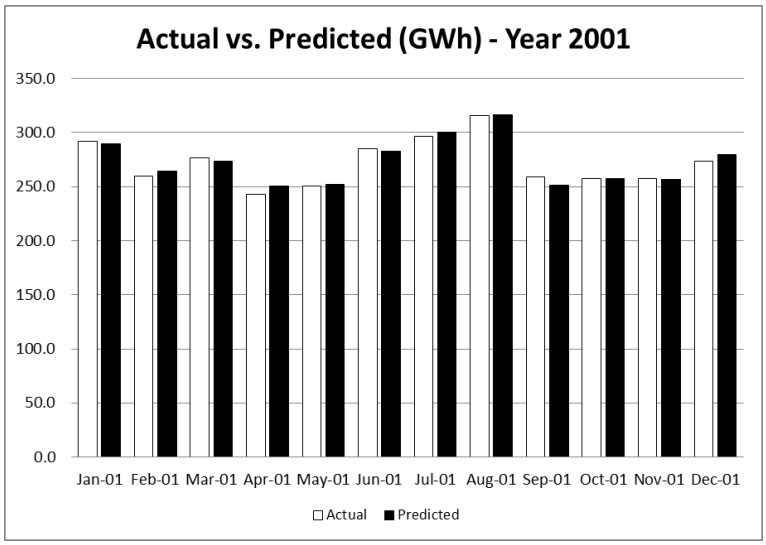


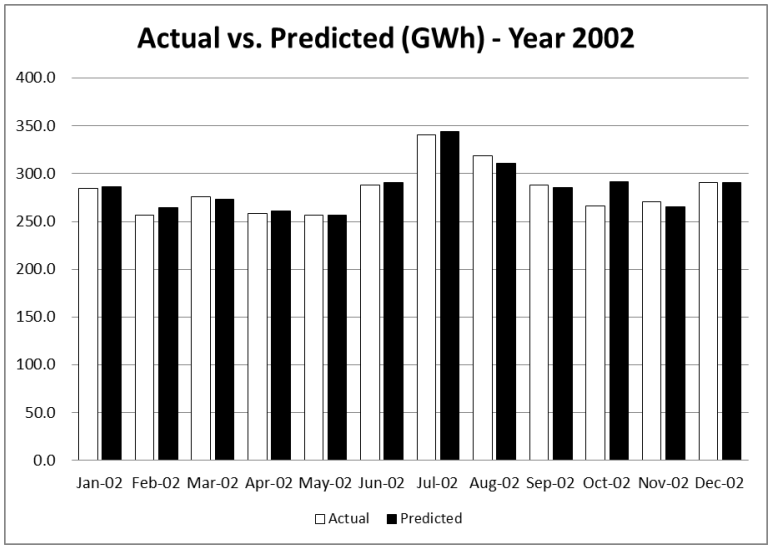

Actual vs. Predicted (GWh) - Year 1997
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-97 Feb-97 Mar-97 Apr-97 May-97 Jun-97 Jul-97 Aug-97 Sep-97 Oct-97 Nov-97 Dec-97
Actual
Predicted

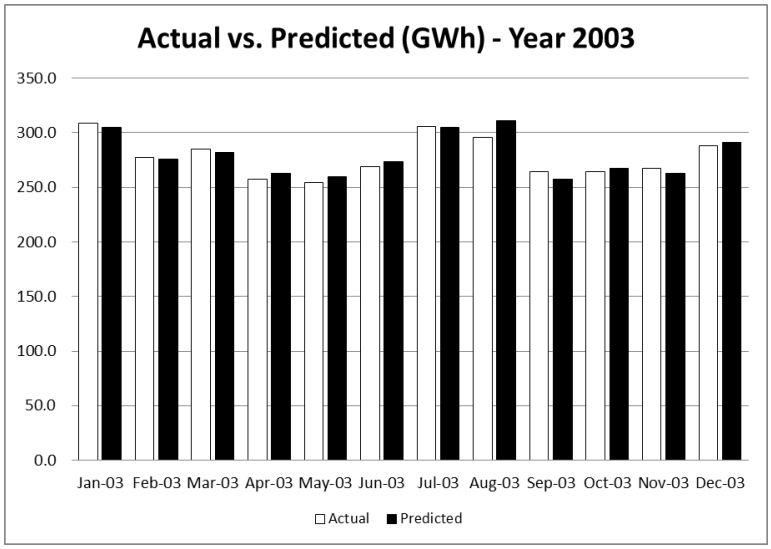

Actual vs. Predicted (GWh) - Year 1998
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-98 Feb-98 Mar-98 Apr-98 May-98 Jun-98 Jul-98 Aug-98 Sep-98 Oct-98 Nov-98 Dec-98
Actual
Predicted

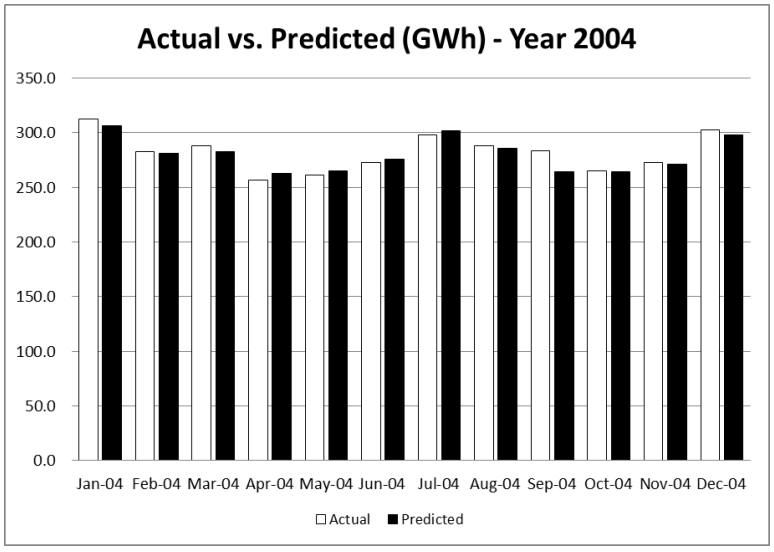

Actual vs. Predicted (GWh) - Year 1999
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-99 Feb-99 Mar-99 Apr-99 May-99 Jun-99 Jul-99 Aug-99 Sep-99 Oct-99 Nov-99 Dec-99
Actual
Predicted

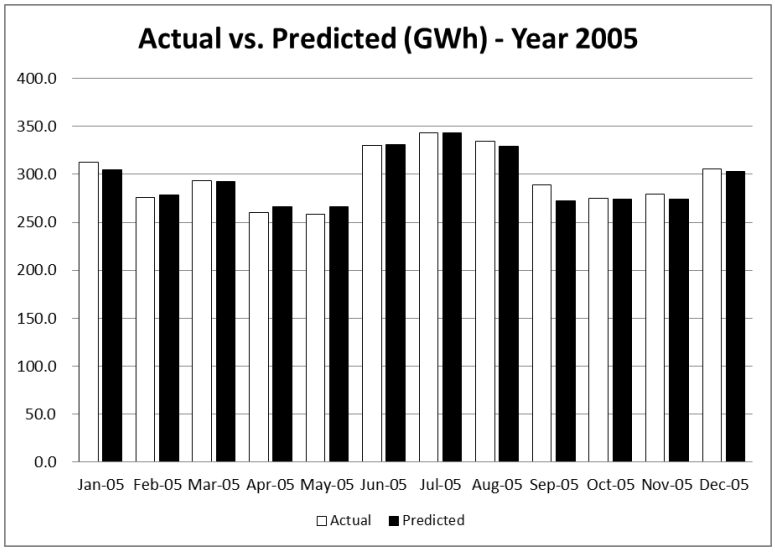

Actual vs. Predicted (GWh) - Year 2000
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-00 Feb-00 Mar-00 Apr-00 May-00 Jun-00 Jul-00 Aug-00 Sep-00 Oct-00 Nov-00 Dec-00
Actual
Predicted

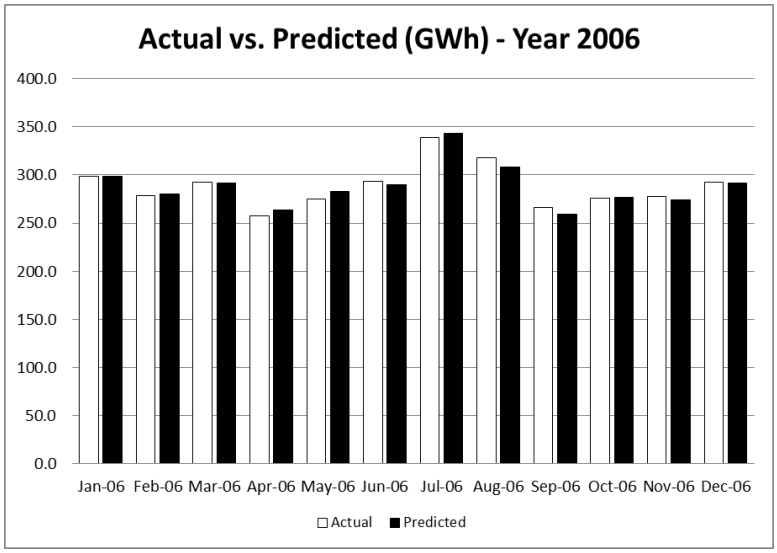

Actual vs. Predicted (GWh) - Year 2001
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-01 Feb-01 Mar-01 Apr-01 May-01 Jun-01 Jul-01 Aug-01 Sep-01 Oct-01 Nov-01 Dec-01
Actual
Predicted

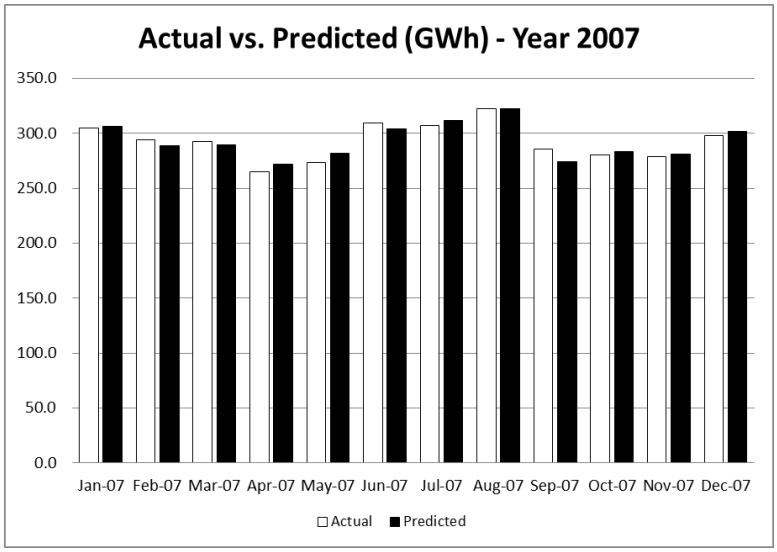

Actual vs. Predicted (GWh) - Year 2002
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-02 Feb-02 Mar-02 Apr-02 May-02 Jun-02 Jul-02 Aug-02 Sep-02 Oct-02 Nov-02 Dec-02
Actual
Predicted

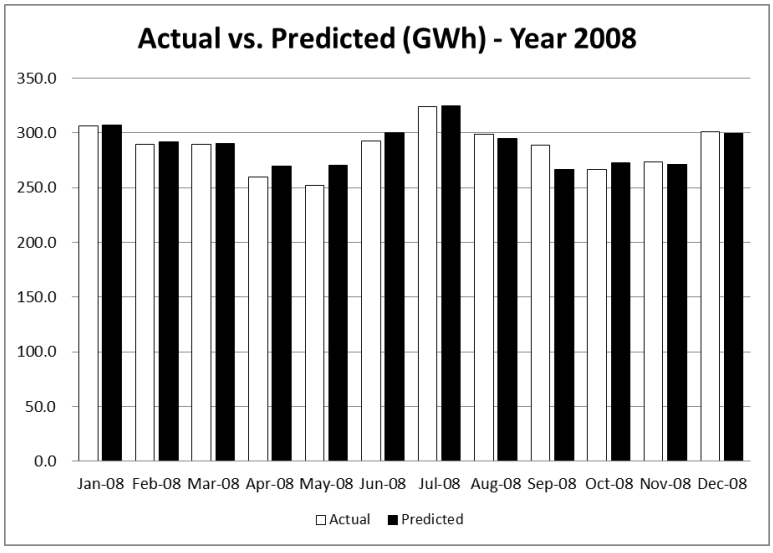

Actual vs. Predicted (GWh) - Year 2003
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-03 Feb-03 Mar-03 Apr-03 May-03 Jun-03 Jul-03 Aug-03 Sep-03 Oct-03 Nov-03 Dec-03
Actual
Predicted

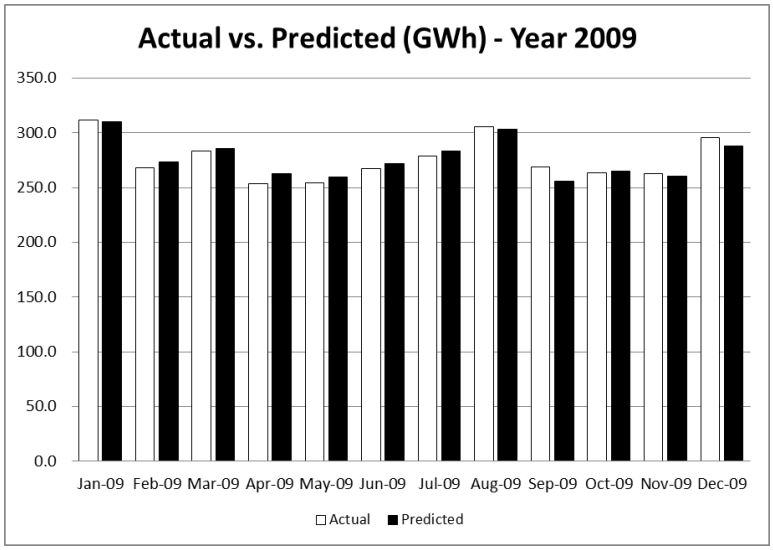

Actual vs. Predicted (GWh) - Year 2004
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-04 Feb-04 Mar-04 Apr-04 May-04 Jun-04 Jul-04 Aug-04 Sep-04 Oct-04 Nov-04 Dec-04
Actual
Predicted

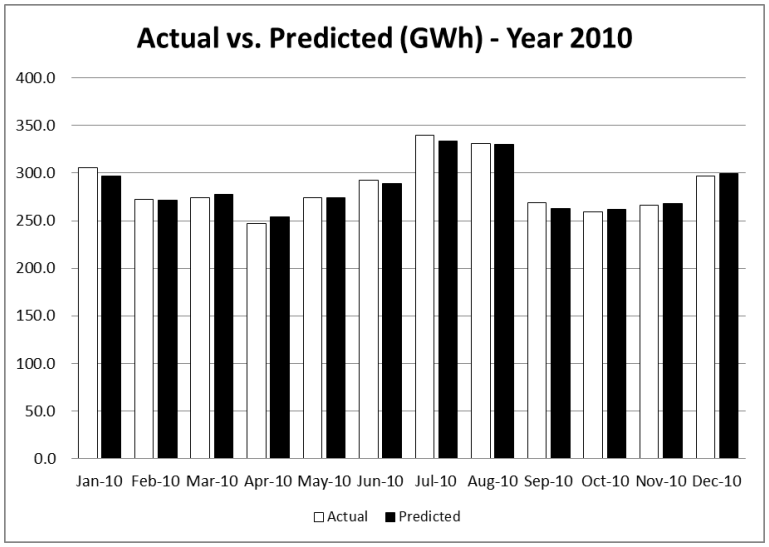

Actual vs. Predicted (GWh) - Year 2005
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-05 Feb-05 Mar-05 Apr-05 May-05 Jun-05 Jul-05 Aug-05 Sep-05 Oct-05 Nov-05 Dec-05
Actual
Predicted

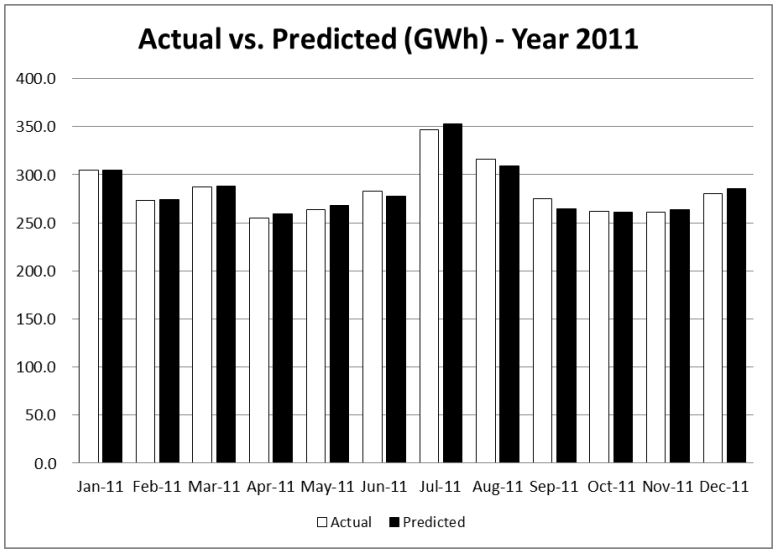

Actual vs. Predicted (GWh) - Year 2006
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-06 Feb-06 Mar-06 Apr-06 May-06 Jun-06 Jul-06 Aug-06 Sep-06 Oct-06 Nov-06 Dec-06
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2007
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-07 Feb-07 Mar-07 Apr-07 May-07 Jun-07 Jul-07 Aug-07 Sep-07 Oct-07 Nov-07 Dec-07
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2008
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-08 Feb-08 Mar-08 Apr-08 May-08 Jun-08 Jul-08 Aug-08 Sep-08 Oct-08 Nov-08 Dec-08
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2009
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-09 Feb-09 Mar-09 Apr-09 May-09 Jun-09 Jul-09 Aug-09 Sep-09 Oct-09 Nov-09 Dec-09
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2010
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-10 Feb-10 Mar-10 Apr-10 May-10 Jun-10 Jul-10 Aug-10 Sep-10 Oct-10 Nov-10 Dec-10
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2011
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-11 Feb-11 Mar-11 Apr-11 May-11 Jun-11 Jul-11 Aug-11 Sep-11 Oct-11 Nov-11 Dec-11
Actual
Predicted

c) The mean average absolute error of the regression equation based on the monthly forecasted values 1.7%.

Load Forecasting and CDM

Question OEB 20

Reference: Exh 3 / pg. 13-16
London Hydro states that its regression model uses monthly kWh and monthly values of independent variables from January 1996 to December 2011 to determine a prediction formula with coefficients for each independent variable.
London Hydro further states that for the CDM activity variable, the years 2006 to 2013 have used a combination of two inputs. London Hydro has used the net energy savings from the Ontario Power Authority ("OPA") 2006-2010 Final CDM Results to show how these programs have persistent savings from 2007 to 2013, but have adjusted for the years 2011 to 2013 to include preliminary actual results from 2011 programs that contribute towards London Hydro's 2011-2014 cumulative energy (kWh) target of 156,640,000 kWh.
London Hydro notes that, for 2013, the monthly values for the CDM activity variable will total 78,975,064 kWh which includes 56,958,662 kWh from the OPA final results plus 22,016,402 kWh reflecting the persistence of 2011 programs into 2013.

a) The OPA has released its final results for 2011 CDM programs in the meantime since London Hydro submitted its application. Please update the CDM variable to account for London Hydro's 2011 final verified CDM results as found within its 2011 CDM Annual Report.
b) Please provide an update to the CDM variable amount that reflects the persistence of 2011 programs into 2013. Please include an explicit CDM variable amount in kWh for the persistence of 2011 programs into 2013.
c) Using the information developed in b), please provide an updated base forecast for the 2013 test year taking into account the persistence of 2006 to 2010 CDM programs only. Then, provide the manual CDM adjustment for each of 2012 bridge and 2013 test years reflecting the persistence and impact of 2011 to 2013 CDM programs, as appropriate.

Response OEB 20

a) The CDM activity variable has been updated to account for London Hydro's 2011 final verified CDM results as found within its 2011 CDM Annual Report and has been used to provide the results in b).

b) It is assumed that Board staff is requesting a revised load forecast reflecting the updated CDM activity variable. The following provides the statistics associated with the regression analysis that includes the updated CDM activity variable. In addition, an updated version of Table 3-9 has been provided reflecting the updated CDM variable.

Statistics		
R Square	94.5%	
Adjusted R Square	94.3%	
F Test	392.6	
Variable	Coefficients	T-stat
Intercept	(99,275,706)	(5.31)
Heating Degree Days	53,992	18.51
Cooling Degree Days	576,720	24.96
Ontario Real GDP Monthly	1,099,164	25.52
Number of Days in Month	5,768,374	9.38
Spring Fall Flag	(8,832,358)	(7.16)
Number of Customers	124	2.61
CDM Activity	(2.2)	(8.44)
Number of Peak Hours	69,140	2.30

Table 3-9: Total System Purchases - Updated CDM Activity Variable			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
1996	2,928.4	2,917.5	(0.4%)
1997	2,913.9	2,934.2	0.7%
1998	3,015.4	3,047.4	1.1%
1999	3,214.5	3,161.1	(1.7%)
2000	3,211.3	3,201.9	(0.3%)
2001	3,266.8	3,275.0	0.3%
2002	3,396.5	3,420.8	0.7%
2003	3,339.3	3,355.6	0.5%
2004	3,384.2	3,360.9	(0.7%)
2005	3,559.6	3,537.4	(0.6%)
2006	3,463.6	3,461.0	(0.1%)
2007	3,513.7	3,518.8	0.1%
2008	3,442.6	3,461.4	0.5%
2009	3,315.9	3,320.8	0.1%
2010	3,428.2	3,419.9	(0.2%)
2011	3,408.6	3,408.6	(0.0%)
2012 Weather Normal		**3,427.5**	
2013 Weather Normal		**3,471.0**	
2013 Weather Normal - 10 year average		**3,480.0**	
2013 Weather Normal - 20 year trend		**3,492.2**	

c) The following table provides a total 2012 and 2013 billed kWh forecast. As shown in the table, this forecast assumes an updated base forecast for the 2012 and 2013 test year taking into account the persistence of 2006 to 2010 CDM programs only in the CDM activity variable. A manual CDM adjustment has been applied to each of 2012 and 2013 reflecting the persistence and impact of 2011 to 2013 CDM programs using the net to gross factor assumed in the application.

Billed (kWh) - CDM Activity Variable reflects 2006 to 2010 OPA programs and CDM manual adjustment includes 2011 to 2013 programs		
	2012	2013
Base	3,338,032,725	3,380,218,083
CDM Manual Adjustment	(54,391,445)	(74,281,037)
Total	3,283,641,280	3,305,937,046

Question OEB 21

References:

i. Exh 3/pp. 13-16;
ii. Load Forecasting Excel Model

London Hydro has included a CDM variable in the purchased system kWh load forecasting regression model used to develop in load forecast. As documented in the Application, the CDM variable has an estimated coefficient of (2.17) with a t-statistic of (8.4) (p=1.2E-22).
On page 15 of this exhibit, London Hydro provides the following documentation of the CDM variable:

> *"The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values grow at constant value over the year. For the years 2006 to 2013, the addition of the monthly CDM activity values shown in Appendix 3A will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for London Hydro. These values reflect the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include draft verified results from 2011 programs that contribute to the four year licensed CDM kWh target of 156,640,000 assigned to London Hydro. The 2011 draft verified results are based on the Draft 2011 Results Report provided to London Hydro by the OPA on July 25, 2012. The 2011 draft verified results have been included in the CDM activity variable since these results have impacted the actual 2011 power purchases. The following Table 3-7 – 2011 Draft Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact outlines the adjustments made to the Net Energy Savings from the OPA 2006-2010 Final CDM Results to include the impact of the draft verified results from 2011 CDM programs and the persistent impact of the 2011 programs into 2012 and 2013. In addition, the table provides the Net Energy Savings from the OPA 2006-2010 Final CDM Results for the years 2006 to 2013. For 2013, the monthly values for the CDM activity variable will total 78,975,064 kWh which includes 56,958,662 kWh from the OPA*

final results plus 22,016,402 kWh reflecting the persistence of 2011 programs into 2013."

Sheet 'CDM Activity' of the Load Forecasting model provides the derivation of the CDM variable. London Hydro's data are shown, but the formulae used to derive the monthly values are not.

Board staff has analyzed the description of the CDM variable documented on page 15 of Exhibit 3 and the data found on sheet 'CDM Activity' of the spreadsheet: London_Hydro_Load Forecast_Data_2013_COS_xls_20120928_updated20121004.xls.

The following is Board staff's understanding of the construction of the CDM variable:

1. *The variable used is the measured Net OPA savings. This is an annualized number of the measured CDM savings for OPA or other approved programs in the year, representing the persistence of prior year programs and new programs in the year. The net results are 'net' of free drivers, free riders, spillover, and other conservation impacts of customers that undertake conservation for reasons other than the OPA or other approved programs. The reported results are also annualized, meaning that the reported measure assumes that the effects of all programs, including the CDM programs in that year, are in place for the full year. In other words, current year programs are assumed to be in effect as of 12:00:01 a.m. on January 1 of the year.*

2. *As the OPA results are annual numbers, the data must be interpolated to get the monthly results. This is done by the following process to get interpolated monthly results in each year. For the first year:*
    - *2.1. Each month is assigned a value from 1 for January, 2 for February, and so on up to 12 for December.*
    - *2.2. The sum of the 'monthly' values is 78 (i.e., $\sum_{i=1}^{12} i = 78$).*
    - *2.3. For the first year, then the monthly increment is 10,202,891/78 = 130,806.*
    - *2.4. The value for each month in the year is then the previous month's value plus the increment. Thus, January 2006 = 130,806, February = 130,806 + 130,806=261,613, March = 261,613 + 130,806 = 392,419, etc. As a result, the December 2006 value is 1,569,676.*
    - *2.5. Next, an 'annualized' total is calculated by multiplying the December value X 12 months, for an 'annualized' CDM savings of 18,836,107.*

3. *For the next year, the incremental CDM savings is calculated by subtracting the measured OPA 'net' savings from the annualized number from step 2.5 above. Thus for 2007, the increment is 21,924,457 – 18,836,107 = 3,088,350.*
    - *3.1. As for step 2.3, the monthly increment is 3,088,350/78 = 39,594.*
    - *3.2. January 2007 = December 2006 + 2007 monthly increment = 1,569,676 + 39,594 = 1,609,270.*

3.3. The value for each subsequent month is calculated as per step 2.4 above.
3.4. The annualized total is calculated by multiplying the December value X 12 months, per step 2.5 above.

4. Step 3. is repeated for each subsequent year from 2008 up to and including 2013. The 2012 and 2013 results reflect the persistence of 2006 to 2011 CDM programs in 2012 and 2013, but not the effects of any 2012 or 2013 CDM programs.

Questions and requests:

a) Please confirm or correct the above explanation of the constructed CDM variable.
b) Based on the OPA's documentation, the reported results are already annualized – i.e. assuming that all programs, including new ones, are in place for the full calendar year.
i. Please state whether this is London Hydro's understanding of OPA reported results. In the alternative, please explain.
ii. If London Hydro agrees that the OPA reports are annualized, what is London Hydro's rationale for calculating another and different "annualized" amount by multiplying the December value by twelve months.
c) Whereas net OPA results may be appropriate for establishing the threshold for the LRAMVA, gross OPA results (i.e. adjusted for losses and free drivers) would be a more suitable value for reflecting the impact of CDM on purchased power.
i. Does London Hydro agree with this statement.? If not, please explain why it believes that net results are more appropriate to explain purchased power.
ii. If London Hydro agrees with the statement, why is the CDM variable that is used in its regression analysis based on net CDM savings?
iii. The interpolation of monthly results within each year means that there is a linear increase or decrease to the CDM values within each time period. However, CDM impacts would more reasonably be expected to be flat (e.g., due to programs like LED streetlighting or refrigerator round-ups), or show cyclical or seasonal patterns (e.g., Peaksaver, energy efficient furnace and air conditioners, improved insulation). Thus, the pattern of the constructed CDM variable may not be approximating the influence of CDM activity on the real system consumption, and thus the CDM variable may be reflecting other drivers of consumption or demand. Please provide London Hydro's views as to whether it believes the CDM variable is a reasonable proxy for the influence of CDM activity on demand.
d) In the estimated regression model for system purchased consumption, the estimated coefficient of the CDM variable is (2.17) and is statistically significant. What this means is that, for every 1,000 kWh of measured net CDM, the base forecast, before any CDM adjustment for 2012 and 2013 programs, is reduced by 2,170 kWh. In other words, even using the

constructed variable of net CDM savings, CDM savings from free drivers, free riders, spillover, etc., would be 1,170 kWh for every 1,000 kWh of OPA program CDM savings. This implies a degree of free driver/free ridership different from the average 64% estimated by the ratio of 'gross' to 'net' CDM savings from OPA reported data, as shown on the page 'CDM Activity' of the Load Forecasting Excel spreadsheet.

i. Please provide London Hydro's views on the reasonableness of the estimated CDM coefficient when contrasted against the free ridership ratio from the OPA's published results.

ii. If the CDM coefficient is higher than expected, would not this inflate the impact of CDM on the base forecast arising from the model (i.e. before any adjustments for 2012 and 2013 CDM programs) and hence result in a lower base forecast?

Response OEB 21

a) London Hydro confirms the explanation on how the CDM activity variable was constructed is correct.

b) It is London Hydro's understanding the reported results from the OPA are annualized.

With regards to the multiplying the December value by twelve, this has been done to assume the persistence of results achieved by the end of the year carry on into the next year and in London Hydro's view is not inconsistent with the annualized values reported by the OPA.

c) London Hydro agrees that the gross OPA results might be a more suitable value for reflecting the impact of CDM on purchased power.

The net results were used as it is London Hydro's understanding these values reflected the "official" results from the OPA. It was thought that since the pattern between the gross and net impacts would be similar, it would be better to use the "official" results and let any difference in the gross and net impacts be reflected in the resulting coefficient assigned to the CDM activity variable.

Consistent with the approach outlined above under iii), the CDM activity variable assumes a flat level of new activity each month. However, it also assumes the result of the new activity in one month persists into the next month. For example, looking at a three month period from January to March, in January it is assumed there are efforts made by the LDC to promote the CDM programs and in January 10 units are saved. For February and March, the same effort is made and 10 additional units are saved each month. However, the results in January would persist into February and March. The result of February would also persist into March. This means in total 10 units are saved in January, 20 units in February and 30 units in March. London Hydro believes the CDM variable is a reasonable proxy for the influence of CDM activity on kWh since it reflects a constant level of activity throughout the year but the persistence of results from one month to the other is also addressed. In addition, the results over the year in total will equal the annual level of savings from the final OPA reports.

d) As shown in Exhibit 3, Page 18 of 55, Table 3-9 the level of actual power purchases in 2011 has declined from 2005 by 151 GWh (i.e. 3,559.6 – 3,408.6). Since the CDM activity variable is the only variable in the prediction formula that has a negative coefficient along with different values for the variable in each month, it is London Hydro's view the regression analysis has assigned the pattern of decline from 2005 to 2011 to the CDM activity variable. As shown in, Exhibit 3, Page 16 of 55, Table 3-7, the 2011 net CDM results from 2011 program plus the persistence of 2006 to 2010 OPA CDM programs in 2011 is 83.2 GWh (i.e. 21.6 GWh from 2011 programs plus 61.6 GWh from the persistence of 2006 to 2010 programs). For 2011, the CDM activity variable reflects 83.2 GWh from the impact of CDM programs initiated from the end of 2005 to 2011. Over the same period, actual purchases have declined by 151 GWh and 151 divided by 83.2 is 1.81. This is close to the absolute value of the coefficient for the CDM activity variable. As a result, in London Hydro's view this provides evidence to support the coefficient for the CDM activity variable being (2.17).

However, this also suggests the coefficient on the CDM activity variable is picking up a decline in power purchases that is more than the impact of net CDM results. The decline could be attributed to such items as the difference between gross and net CDM results, the impact of customer perception on electricity pricing once smart meters were installed even though customers were not transitioned to TOU pricing, the real impact of TOU pricing and the impact of economic conditions in the London Hydro service area. London Hydro was not able to separately quantify the impact of these items.

Question OEB 22

References:

i. Exh 3/ / pp. 13-16;

ii. Enhanced version of Load Forecast Excel Model 'London_Hydro_Load Forecast_Data_updated20121004_staff20121210')

Board staff understands that the results as reported by the OPA are "annualized" (i.e. assume that all CDM programs, including the current year's program, are in effect for the full year, from January 1 to December 31). While the full year effect for persistence of prior year CDM programs would be in place for the full year, CDM programs implemented in a given year would normally not have the full impact in the first year, due to timing.

In the absence of any other information, a "half-year" rule (i.e. assuming that only one-half of the incremental impact of a program is realized in the calendar year of introduction) may be used as a proxy for the actual impact, ignoring all other factors (i.e. seasonality).

To implement this, Board staff has constructed variables based on the following methodology, with the graph shown on the following page to assist:

1. *As the OPA results are annual numbers, the data must be interpolated to get the monthly results. This is done by the following process to get interpolated monthly results in each year. For the first year:*
   - *1.1. While each month is numbered from January = 1, February = 2, etc., to December = 12, it is the mid-point value of the month that will allow the area under the line to equate to the annual savings under the mid-year rule, while using the monthly value overstates the area under the line. Thus, January = 0.5, February = 1.5, March = 2.5, etc., to December = 11.5.*
   - *1.2. The sum of the 'monthly' values is 72 (i.e., $\sum_{i=1}^{12}(i - 0.5) = 72$).*

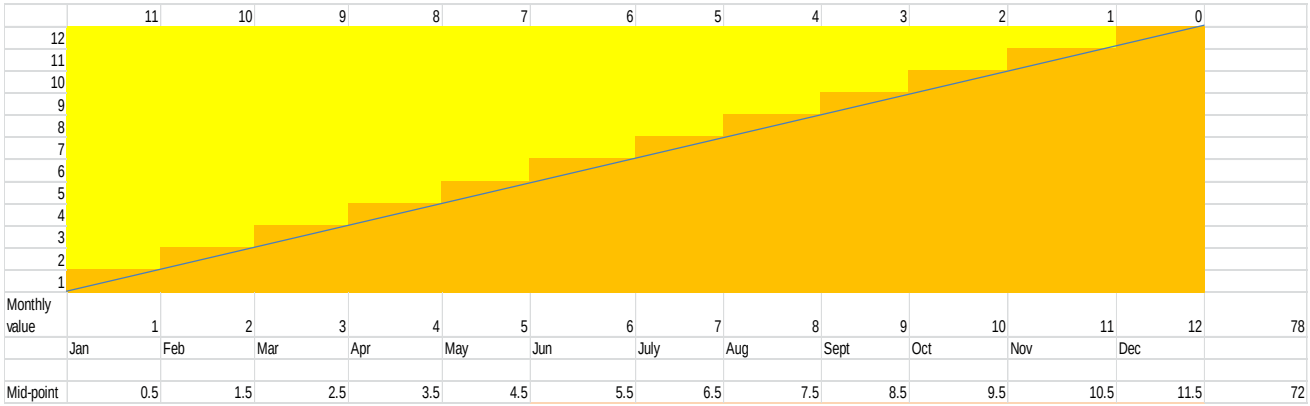
1.3. For the first year (2006), the CDM savings are half of the reported CDM savings of 10,202,891, or 5,101,446 kWh.
1.4. For the first year, then the monthly increment is 5,101,446/72 = 70,853.
1.5. For January 2006, the value is 0.5 X 70,853 = 35,427 kWh.
1.6. The value for each month in the year is then the previous month's value plus the increment. Thus, February = 35,427 + 70,853 = 106,280, March = 106,280 + 70,853 = 177,134, etc. The December 2006 value is 814,814.
1.7. Next, the December 31 endpoint would be the December value + 0.5 X 70,853 = 814,814 + 35,427 = 850,241.

2. For the next year, the incremental CDM savings is calculated by subtracting the measured OPA 'net' savings from the prior year's net saving. Thus for 2007, the increment is 21,924,457 – 10,202,891= 11,721,566.
2.1. Based on the half-year rule, the actual increment for 2007 programs is 11,721,566/2 = 5,680,783.
2.2. Thus the monthly increment for 2007 is 5,680,783/72 = 81,400.
2.3. January 2007 = December 31, 2006 + 0.5 X 2007 monthly increment = 850,241+ 0.5 X 81,400 = 890,941.
2.4. The value for each subsequent month is calculated as per step 1.6 above.
2.5. The December 31, 2007 end value would be the December 2007 value + 0.5 X 2007 increment = 1,786,338 + 0.5 X 81,400 = 1,827,038.

3. Step 2) is repeated for each subsequent year from 2008 up to and including 2013. The 2012 and 2013 results reflect the persistence of 2006 to 2011 CDM programs in 2012 and 2013, but not the effects of any 2012 or 2013 CDM programs.

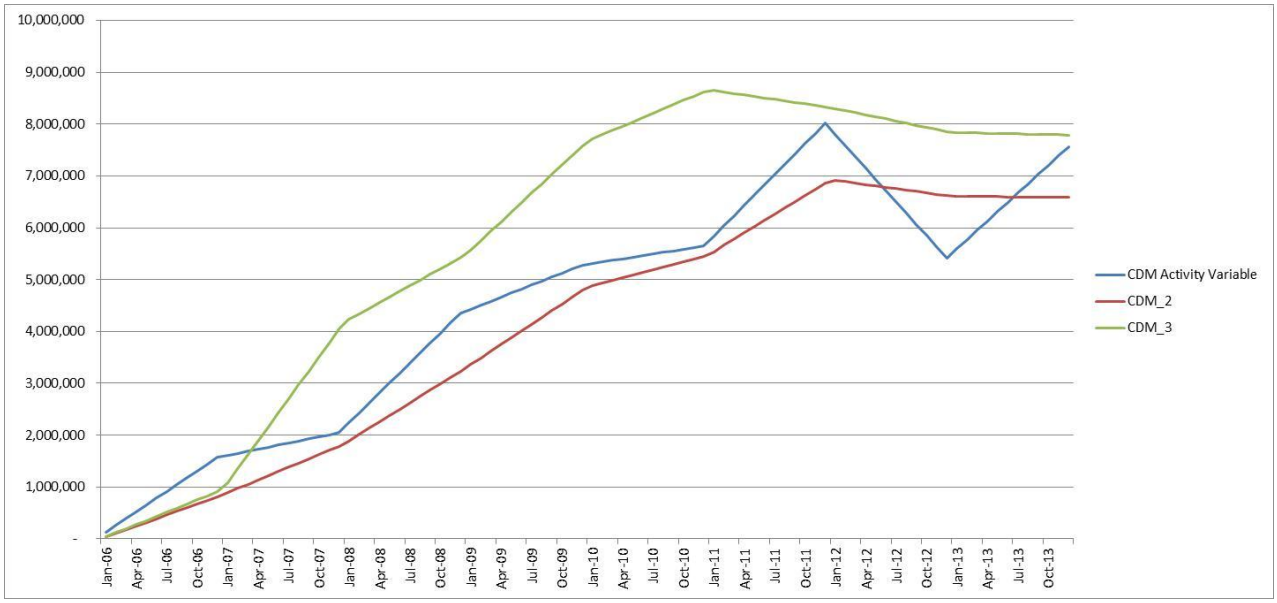
This variable is shown as 'CDM_2' on the sheet 'CDM Activity_kcr', which has been added to London Hydro's updated Excel spreadsheet. (The spreadsheet has been filed separately in the record of this proceeding as 'London_Hydro_Load Forecast_Data_updated20121004_staff20121210'.

The following graph shows the rationale for using the monthly midpoint values for the linear interpolation.



An alternative approach is to use the above methodology but applied to the 'gross' CDM savings as measured by the OPA. This is shown as variable 'CDM_3' on the sheet 'CDM Activity_kcr' of the enhanced Excel spreadsheet.

The following chart plots the interpolated data for the CDM variable as estimated by London Hydro (blue line) and the variables 'CDM_2' (red line) and 'CDM_3' (green line) constructed by Board staff.



Questions / requests:

a) *Please provide London Hydro's views on the reasonableness of the alternative CDM variables for 'net' and 'gross' CDM savings.*
b) *Please provide a regression analysis using CDM_2 in place of the original CDM activity variable. Please provide the regression results as calculated in tabular format by Microsoft Excel. Also provide the annual actual and fitted values based on this, including the predicted values for 2012 and 2013.*
c) *Please provide a regression analysis, as in b) above, using CDM_3 in place of the original CDM activity variable.*
d) *Please comment on the reasonableness of the regression equations, including on the reasonableness of the estimated CDM coefficient for each equation estimated in b) and c).*

Response OEB 22

a) A review of how CDM_2 and CDM_3 variables developed in tab CDM Activity_kcr of the Enhanced version of Load Forecast Excel Model provided by staff titled

'London_Hydro_Load_Forecast_Data_updated20121004_staff20121210' indicates there appears to be an inconsistency between CDM_2 and CDM_3. CDM_2 includes the estimated results and persistence of 2011 programs assumed at the time the application was prepared, but CDM_3 does not include the impact of 2011 programs. Based on this inconsistency, it is difficult for London Hydro to comment on reasonableness of these two variables. However, based on the results provided in b) and c) below, using the CDM_2 variable produces an overall load forecast that is lower than the load forecast using the approach assumed in the London Hydro load forecast. On the other hand, using the CDM_3 variable produces a load forecast that is higher than the London Hydro load forecast. The London Hydro load forecast is right in the middle of the forecasts produced by the CDM_2 and CDM_3 variables. This suggests to London Hydro the approach used in the application could be a more reasonable approach since it produces a "middle of the road" forecast.

b) The following provides the statistics associated with the regression analysis that includes CDM_2 variable in place of the original CDM activity variable. In addition, a revised version of Table 3-9 has been provided reflecting the CDM_2 variable.

Statistics		
R Square	94.4%	
Adjusted R Square	94.2%	
F Test	388.6	
Variable	Coefficients	T-stat
Intercept	(97,460,976)	(5.20)
Heating Degree Days	54,312	18.54
Cooling Degree Days	579,725	24.99
Ontario Real GDP Monthly	1,082,611	25.41
Number of Days in Month	5,749,798	9.30
Spring Fall Flag	(8,727,253)	(7.04)
Number of Customers	122	2.56
CDM Activity	(2.3)	(8.29)
Number of Peak Hours	70,656	2.34

Table 3-9: Total System Purchases - Using CDM_2			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
1996	2,928.4	2,920.1	(0.3%)
1997	2,913.9	2,936.1	0.8%
1998	3,015.4	3,048.7	1.1%
1999	3,214.5	3,161.1	(1.7%)
2000	3,211.3	3,200.2	(0.3%)
2001	3,266.8	3,272.6	0.2%
2002	3,396.5	3,418.4	0.6%
2003	3,339.3	3,351.8	0.4%
2004	3,384.2	3,356.5	(0.8%)
2005	3,559.6	3,532.9	(0.7%)
2006	3,463.6	3,465.5	0.1%
2007	3,513.7	3,522.7	0.3%
2008	3,442.6	3,468.9	0.8%
2009	3,315.9	3,326.9	0.3%
2010	3,428.2	3,412.1	(0.5%)
2011	3,408.6	3,407.8	(0.0%)
2012 Weather Normal		**3,400.6**	
2013 Weather Normal		**3,447.6**	
2013 Weather Normal - 10 year average		**3,456.6**	
2013 Weather Normal - 20 year trend		**3,468.9**	

c) The following provides the statistics associated with the regression analysis that includes CDM_3 variable in place of the original CDM activity variable. In addition, a revised version of Table 3-9 has been provided reflecting the CDM_3 variable.

Statistics		
R Square	94.5%	
Adjusted R Square	94.2%	
F Test	391.1	
Variable	Coefficients	T-stat
Intercept	(98,292,490)	(5.26)
Heating Degree Days	54,327	18.61
Cooling Degree Days	578,716	25.02
Ontario Real GDP Monthly	1,093,330	25.48
Number of Days in Month	5,755,621	9.34
Spring Fall Flag	(8,772,185)	(7.10)
Number of Customers	126	2.64
CDM Activity	(1.6)	(8.39)
Number of Peak Hours	67,965	2.25

Table 3-9: Total System Purchases - Using CDM_3			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
1996	2,928.4	2,918.3	(0.3%)
1997	2,913.9	2,934.8	0.7%
1998	3,015.4	3,047.8	1.1%
1999	3,214.5	3,161.2	(1.7%)
2000	3,211.3	3,201.4	(0.3%)
2001	3,266.8	3,274.3	0.2%
2002	3,396.5	3,420.2	0.7%
2003	3,339.3	3,354.6	0.5%
2004	3,384.2	3,359.6	(0.7%)
2005	3,559.6	3,536.4	(0.7%)
2006	3,463.6	3,472.6	0.3%
2007	3,513.7	3,516.0	0.1%
2008	3,442.6	3,453.6	0.3%
2009	3,315.9	3,320.5	0.1%
2010	3,428.2	3,406.0	(0.6%)
2011	3,408.6	3,425.1	0.5%
2012 Weather Normal		**3,441.9**	
2013 Weather Normal		**3,489.8**	
2013 Weather Normal - 10 year average		**3,498.8**	
2013 Weather Normal - 20 year trend		**3,511.0**	

d) From a statistical perspective the regression equations and the estimated CDM coefficients are reasonable for each equation estimated in b) and c).

The statistical result that support the two equations produce similar statistical results to those achieved in the regression analysis that supports the load forecast in the application.

Question OEB 23

References:

i. *Exh 3 / pp. 13-16;*
ii. *Load Forecasting Excel Model*

On the assumption that the CDM variable is an accurate estimate of the kWh saved by past and current year CDM activities on a 'gross' basis, the coefficient should be constrained to -1.0 in value. With the purchased consumption being modelled, the coefficient should be -1 X (1 + loss factor).
This can be effected by running a regression where the dependent variable is an altered consumption omitting all past CDM, by adding the CDM variable grossed up by (1 + loss factor), and then regressing this altered dependent variable on all included explanatory variables except for CDM. This would then give a base forecast assuming no CDM activity. For the 2013 load forecast, the predicted 2013 forecast from this model would then be manually adjusted for 2012 and 2013 CDM and the estimated persistence of all prior year activities.

Questions / requests

a) *Please run a regression and provide all regression statistics, in which the regression equation is specified as follows:*
   i. *Consumption is estimated as measured consumption + CDM_3 X (1 + loss factor); and*
   ii. *All regressor variables are included, except that CDM activity is excluded*
b) *Please provide the following information using the results of part a):*
   i. *Predicted `base`values, including the forecasted values for 2012 and 2013;*
   ii. *Adjusted 'base' values, calculated as the sum of the predicted 'base' values less CDM_3;*
   iii. *For 2012 and 2013; estimated values that are the sum of adjusted 'base' values (from b) above) less the manual adjustments for the 'gross' impact of 2012 and 2013 CDM programs on 2012 and 2013 forecasts;*
c) *Please comment on the reasonableness of the regression results in parts a) and b), including the reasonableness of the coefficient values and the forecasted 2013 load forecast.*

Response OEB 23

a) The regression analysis has been rerun as per the instruction above for a) and the following table provides the regression statistics.

Statistics		
R Square	94.6%	
Adjusted R Square	94.4%	
F Test	459.4	
Variable	Coefficients	T-stat
Intercept	(93,493,621)	(4.92)
Heating Degree Days	54,887	18.46
Cooling Degree Days	583,238	24.77
Ontario Real GDP Monthly %	1,044,839	25.88
Number of Days in Month	5,834,104	9.29
Spring Fall Flag	(8,640,170)	(6.86)
Number of Customers	88	1.88
Number of Peak Hours	75,393	2.46

b) The requested information is provided below

Year	Actual Base Values - Purchased Power including CDM_3 plus losses	Predicted Base Values - Purhcased Power	CDM_3 plus Loss Factor	Adjusted Base Values - Purchased Power	CDM Adjustment plus Loss Factor	Power Purchased Forecast	Billed Forecast = Power Purchased minus Losses
1996	2,928.4	2,928.0	0.0	2,928.0			
1997	2,913.9	2,942.0	0.0	2,942.0			
1998	3,015.4	3,052.1	0.0	3,052.1			
1999	3,214.5	3,159.9	0.0	3,159.9			
2000	3,211.3	3,195.2	0.0	3,195.2			
2001	3,266.8	3,265.2	0.0	3,265.2			
2002	3,396.5	3,412.1	0.0	3,412.1			
2003	3,339.3	3,339.9	0.0	3,339.9			
2004	3,384.2	3,342.6	0.0	3,342.6			
2005	3,559.6	3,517.6	0.0	3,517.6			
2006	3,469.5	3,459.1	(5.9)	3,453.2			
2007	3,545.6	3,540.0	(31.9)	3,508.1			
2008	3,502.7	3,519.2	(60.1)	3,459.1			
2009	3,397.7	3,421.5	(81.8)	3,339.7			
2010	3,529.8	3,535.5	(101.6)	3,433.9			
2011	3,514.3	3,559.3	(105.7)	3,453.6			
2012 Weather Normal		**3,567.3**	**(100.5)**	**3,466.8**	**(19.6)**	**3,447.1**	**3,324.2**
2013 Weather Normal		**3,605.8**	**(97.2)**	**3,508.6**	**(39.2)**	**3,469.3**	**3,345.5**

c) London Hydro is concerned with the results of this analysis since, as stated above in response to Board staff 22 a), it appears the variable CDM_3 does not include the estimated results and persistence of 2011 programs. As results, the impact of the 2011 programs has not been reflected in the forecast provided in b).

Operating Costs (Exhibit 4)

Issue 4.1 Is the proposed overall forecast for total OM&A costs for the 2013 Test Year appropriate?

Emergency Financial Assistance

Question OEB 24

Reference: Exh 4 / p. 32

Please confirm that London Hydro does not include in its revenue requirement the cost of any emergency financial assistance other than LEAP (eg. legacy programs such as Winter Warmth). If not confirmed, please describe the nature and cost of the financial assistance.

Response OEB 24:

London Hydro confirms that the cost of any emergency financial assistance other than to LEAP is not included in its revenue requirement.

Advertising Expense

Question OEB 25

References: Exh 4, pp. 59 and 86

a) *Please explain the nature and purpose of London Hydro's total advertising expense of $586,260, included in Table 4-42 on p. 86*

b) *Please explain the purpose of London Hydro's forecast purchase of Advertising at a cost of $217,400, shown in Table 4-27 on p. 59.*

Response OEB 25:

Preamble to response for clarification purposes: London Hydro's Application presents costs and variances from two different perspectives. Firstly, it presents costs and variances by major cost category, such as labour, purchased services, and materials and supplies and are not activity specific. The second perspective is based on the OEB Uniform System of Accounts ("USoA") format which is activity based and is a mix of many cost categories.

Please refer to Page 35 and Page 79 for further discussion related to cost and variance presentations contained in the two separate sections of London Hydro's Application.

Table 4-42 on Page 86 referred to in part a) of this question is based on the OEB USoA format and includes all costs related to the activity known as OEB 5660 - General Advertising Expense. Part b) of this question refers to Advertising expense within Table 4-27 on Page 59 which is a single specific cost within the major cost category known as purchased services. It is not entirely related to the costs presented in OEB account 5660 – General Advertising as a portion of these costs are grouped in OEB 5410 – Community Relations, Sundry.

a) London Hydro's total General Advertising Expense of $586,260, included in Table 4-42, is presented in the OEB's USoA format. The purpose and nature includes:

- The cost of labour, materials used, advertising expenses, and other costs incurred related to corporate communication with the public, customers, and employees
- To promote the utility or the industry, promote goodwill and the corporate profile within the community and industry, to inform the public concerning matters that affect London Hydro's operations, such as the cost of providing service, efforts to improve service levels, efforts to improve and protect the environment, etc.
- To provide public education and safety communications
- To provide the customer with current information related to industry changes and London Hydro operations such as time of use billing, outage management, etc. and to promote new web based self-service facilities and enhance/update information on London Hydro's corporate website
- To ensure London Hydro's workforce is knowledgeable about the industry, regulation, and on-going changes

The following Table identifies the various components included in Total General Advertising expense and provides additional information related to the nature and purpose of the expenses.

Table E4 – OEB 25 a)

General Advertising Expense (OEB 5660) - Nature and Purpose		
Cost Category	**2013 TEST Year ($)**	**Description**
Labour and Benefits	341,460	Employee's salaries and benefits for approximately 3 FTE's
Advertising - Corporate Communication	105,000	Preparing advertising material for newspapers, radio, billboards, etc. to increase communication and awareness for the public regarding London Hydro and industry activities.
Advertising - Tenders	27,400	Contract tendering advertising consistent with corporate purchasing policy.
Consulting	35,500	Cost related to obtaining the services of an external consulting professional to assist in enhancing London Hydro's profile within the community and the industry
Materials & Supplies	28,600	Various items such as office materials and supplies, promotional goods etc. required to execute the functions of the Corporate Communication Department
Studies & Special Projects	25,000	Benchmarking Survey - Customer Satisfaction
Business Equipment & Communication	9,300	Cost of equipment and communication tools required to carry out the function of the Corporate Communications Department
Employee Development	6,900	Employees continuing professional development and education
Meeting expenses	5,400	Cost to attend industry meetings, conferences, etc. relating to the Corporate Communications Department
Corporate Membership Fees	1,700	Costs of professional association dues and corporate memberships
Total OEB 5660 - General Advertising Expense	**$ 586,260**	

Labour and Benefits:

This is the total labour and benefit cost for the management and delivery of Corporate Communications required to support London Hydro's customers, community, and employees. London Hydro continues to focus on maintaining strong relationships with the public through the delivery of effective communication programs.

The introduction of time of use billings, customers' demand for educational and outage information, and online data has all led to increased levels of communications.

Also, London Hydro faces a significant level of employee turnover. As many employees approach retirement London Hydro will need to replace these resources with new, less experienced employees who will rely on internal communications as they adapt to the corporation and industry. An informed workforce is critical as many are in direct contact with our customers and the public on a daily basis.

Advertising (Corporate Communication and Tenders):

Consistent with London Hydro's strategic planning and forward looking goals there will be a focus on increasing communications with the public. This can be in the form of billing inserts, billboard advertisements, and radio airtime, among others. Time of use billings, customer self-service online tools such as "My Account", and other website enhancements are all driving forces that London Hydro needs to address to ensure its customers are kept well informed in a changing business environment.

Additionally, the cost of advertising for tendering of contracts and proposals in order to ensure London Hydro seeks and obtains the services that offer the best value for our customers is included.

Consulting:

London Hydro has a very strong presence in the school curriculum. External consultants are contracted to conduct workshops to educate local grade 5 and 6 teachers regarding electricity from generation to end use. This program has been very well received and is now carried out by other utilities.

External consultants will also play an important role as London Hydro focuses on enhancing our corporate profile within the community and with our customers.

Materials and Supplies:

Included in Materials and Supplies are various items such as small office equipment and supplies, publications and subscriptions, stationary, as well as promotional goods and programs. All of these items are used in carrying out the day to day operations of the Corporate Communications Department. Promotional goods are geared to promoting awareness of the organization within the community.

Studies and Special Projects:

London Hydro carries out an annual Customer Care Satisfaction Survey which provides valuable feedback from our customers, rating London Hydro in various categories. This feedback highlights areas that London Hydro is succeeding in as

well as any areas that require improvement, thereby allowing Management to make informed strategic decisions to better serve our customers.

Business Equipment and Communications:

Included in Business Equipment and Communications are items such as, photocopier equipment, telephones, cell phones and communications devices. All are necessary to carry out the day to day operations of the Corporate Communications Department.

Employee Development:

In order to maintain a skilled workforce and promote employee development London Hydro encourages employees to continue to enhance their skills as related to their job requirements. The employee development costs associated with general advertising relate to the employees in the Corporate Communications Department going to various conferences, taking educational courses, or attending seminars all in an effort to increase their own knowledge and understanding of the industry and how it relates to their roles.

Meeting Expenses:

These expenses relate to meetings and conferences which provide on-going updates related to industry specific information and trends which is invaluable in the development and deployment of appropriate communications to the public.

Corporate Membership Fees:

This represents the cost for London Hydro to be a member of certain associations and organizations, such as the local Chamber of Commerce, thereby allowing London Hydro to promote its corporate profile and increase visibility within the community.

b) The following Table provides the purpose of London Hydro's forecast purchase of Advertising at a cost of $217,400 and lists the applicable OEB Account under the USoA presentation that these costs are included in.

Table E4 – OEB 25 b)

Advertising Expense	Amount $	included in: OEB USoA	Description
Advertising - Corporate Communication	105,000	5660	Preparing advertsing material for newspapers, radio, billboards, etc. to increase communication and awareness for the public regarding London Hydro and industry activities.
Advertising - Tenders	27,400	5660	Contract tendering advertising consistent with corporate purchasing policy.
Advertising - Community Relations	85,000	5410	Costs associated with community involvement
Total Advertising Expense	**$ 217,400**		

Advertising (Corporate Communication and Tenders):

As described in part a) above, this expense is included in OEB 5660 – General Advertising Expense.

Community Relations Advertising:

A significant focus of London Hydro's strategic plan is to continue to promote the organization within the community and maintain a positive relationship with its customers and the general public. As such, London Hydro is involved in various sponsorships and community relations partnerships within the community. For example, London Hydro sponsored an exhibit at the Children's Museum of London to help educate the public on electrical safety awareness as a way of giving back to the community.

Other items included in this are advertising materials and information bulletins used as a means of communicating with the community on any matters relating to community involvement.

Community Relations Advertising is included in OEB 5410 – Community Relations, Sundry.

Cost Drivers

Question OEB 26

i. *References: Exh 4, p. 4*

ii. *London Hydro's Strategic Plan, Exh 1, Appendix 1A*

London Hydro has indicated that forecasts are impacted by significant business environment changes impacting London Hydro as well as all distribution companies in the province.

Please quantify the reduction or net effect on OM&A forecasts had there been no significant business environment changes mentioned in London Hydro's Strategic Plan.

Response OEB 26:

London Hydro's Strategic Plan (Exhibit 1, Appendix 1A) identifies significant business environment changes that are key cost drivers impacting London Hydro and the 2013 Test Year OM&A costs. These cost drivers are common to all distribution companies in the province.

The following table lists these business environment changes:

Significant Business Environment Changes	
DESCRIPTION	CODE
Time of Use Billing	TOU
Emerging Technologies	TECH
Succession Planning	SUCPLN
Accounting Standards (IFRS and MIFRS for rate making)	MIFRS
Regulatory Change, Complexity, and Compliance	REG

The significant business environment changes are reflected in the total change in OM&A costs, and impact cost categories such as labour, materials, hardware and software expense, employee development and training, and customer communications expense, among others. Once the impact of these business environment changes are removed the net change to London Hydro's "baseline" business over the 2009 Actuals can be better compared.

Table E4 – OEB 26 quantifies the reduction or net effect on OM&A forecasts had there been no significant business environment changes. The Table starts with OM&A expense for the 2013 Test Year as submitted in this Application (Table 4-1, Page 1), and lists the cost impacts due to these business environment changes. Table E4 – OEB 26 below contains some main references to further discussion/evidence provided within Exhibit 4, as well as identifies the specific business environment changes impacting each item.

Table E4 – OEB 26

	COST DRIVER CODE:	Rate Application MAIN REFERENCES:	2009 Actual (CGAAP)	2013 TEST (MIFRS)	Overall Change		Average Annual Change
TOTAL Operating, Maintenance, & Administration		E4, Table 4-1, Page 1	**$ 27,744**	**$ 33,745**	**$ 6,001**	**21.6%**	**5.4%**
REDUCTIONS:		Cost Driver Tables 4-12, 4-13					
LABOUR: (salaries and benefits)							
Engineering and Operations - Engineer positions	SUCPLN/TECH	E4, Page 45, OEB #28		$ (388)			
Corporate Services - Communication Assistant position	TECH/REG	E4, Page 46-47, OEB #25		(82)			
Corporate Services - Billing Support positions	TECH/REG/TOU	E4, Page 46-47		(271)			
Corporate Services - Meter Data Management	TECH/TOU	E4, Page 46-47		nil			
Financial Services - Accountant position	MIFRS/REG	E4, Page 47		(100)			
Executive Services - Chief Information Officer	TECH/REG/TOU	E4, Page 48-49		(187)			
Executive Services - SAP Specialist positions	TECH/REG/TOU	E4, Page 48-49		(278)			
Executive Services - SAP System Supervisor	TECH/REG/TOU	E4, Page 48-49		(139)			
				$ (1,445)			
NON LABOUR:							
Change in Capitalization of Overhead	MIFRS	E4, Page 3, Line 13-14		$ (336)			
Hardware and software license and maintenance cost	TECH/TOU	E4, Page 3, Line 15-18, Page 63-67		(508)			
Smart Meter Operating Cost - Non labour	TOU	E4, Page 11		(443)			
Change in Meter Reading Contracted Service Cost	TECH	E4, Page 59		297			
Employee Development / Training	TECH/SUCPLN/REG	E4, Page 71		(158)			
Billing System Support - External	TECH/REG	E4, Page 59		(451)			
Community Relations - information programs	TOU/REG	E4, Page ##, OEB #25		(62)			
				$ (1,661)			
Net OM&A BEFORE Significant Business Environment Changes			**$ 27,744**	**$ 30,639**	**$ 2,895**	**10.4%**	**2.6%**

Reductions from Labour:

The net headcount change in OM&A between the 2009 Actual and the 2013 Test Year is 16.7 FTEs as shown in Exhibit 4, Table 4-22, on Page 44. As identified above 12.5 new

FTEs are related to the changing business environment. The incremental employee expenses related to these FTEs have been excluded from the above analysis for simplicity.

Through departmental and corporate restructuring initiatives London Hydro has re-deployed many existing positions and gained efficiencies to meet the general operational and administrative needs of the Company wherever possible to minimize the addition of full time staff in OM&A.

With the reductions in FTEs due to significant environmental changes taken into account, London Hydro requires an additional 4.2 FTEs over than the 2009 Actual FTE level for OM&A activities. This is a 2.1% increase in total FTEs supporting OM&A activities over the 2009 Actuals.

Reductions from Non-Labour:

Changes in accounting standards, MIFRS, succession planning, the implementation of time of use billing, and other regulatory requirements have impacted non-labour expenses such as employee development, billing system support, and hardware and software expenses, among others. Gross non-labour expenses have increased 23.5% over the 2009 Actuals, however, with no significant business environment changes this increase would have been 10.1% or 2.5% per year.

Net OM&A before Significant Environmental Changes:

As shown above, London Hydro would have expected an overall increase in OM&A of $2.9 million or 10.4% (2.6% per year) over the 2009 Actuals had there been no significant business environment changes. London Hydro has managed to find significant efficiency gains to partly offset wage, benefit and other cost increases that have been fully described within Exhibit 4.

Question OEB 27

Reference: Exh 4, p.6

London Hydro indicated that its intention is to lessen the dependency on external contractors in numerous areas such as construction and information technology. London

Hydro noted that some of the numerous benefits related to this shift are reductions in cost, improving in-house skill knowledge, consistency, and improved issue response.

a) *Please provide a cost and benefit analysis between the external contractors London Hydro used to use and the London Hydro's move to using internal resources.*

b) *Please provide a comparative analysis on the expenses incurred between London Hydro's external contractors and London Hydro's forecasted expenses for internal resources.*

Response OEB 27:

a) London Hydro has provided two cost/benefit analyses to support the change in mix between internal labour and external contractors related specifically to construction and information services. Each area is described separately below.

In both cases, internal labour and external contractors are used to support various OM&A and capital activities as required. The mix to support both capital and OM&A activities can change year to year depending on maintenance requirements, availability of resources, and the scope, demand, and timing of the required operating or capital work.

The following information should be read in conjunction with other evidence included in Exhibit 4 as well as the London Hydro Strategic Plan (Exhibit 1, Appendix 1A).

Construction:

London Hydro uses a mix of internal labour and external contractors to support both operating and capital construction activities.

London Hydro will continue to use external contractors for new subdivision construction, subdivision rebuilds and duct and manhole construction, however, it will rely on them less in the future. In 2009, three construction workers left the department and they were not immediately replaced. Capital projects were augmented with additional external contracted labour as required. The re-hiring of

the three construction worker positions in the construction department will reduce the cost of capital projects and will not significantly impact on total OM&A costs.

The cost of two new secondary cable servicer positions in the construction department will result in reduced external contractor labour in OM&A and will eliminate inefficiencies in the repair process. Once fully trained, these positions will provide a turnkey service to locate, dig up, and repair secondary cable faults thereby eliminating the need to co-ordinate the repair using both external contractors and higher cost electric underground journeymen.

Please refer to further discussion related to Engineering and Operations department labour on Page 45 of Exhibit 4.

A cost comparison was completed to compare the total Labour (L), Vehicle (V) and Equipment (E) costs related to subdivision projects completed by London Hydro crews to those projects completed by externally contracted crews. London Hydro has reviewed [%L+V+E cost] compared to the [Total cost] of a project to measure productivity and cost.

On average, London Hydro's internal labour and equipment costs as a percentage of total cost are lower than the outsourcing option as shown in Table E4 – OEB 27a). London Hydro's cost review was based on a sample of capital projects and shows London Hydro's internal labour, vehicle and equipment costs average 25.7% of the total project cost. The outsourced option averages 31.7% of the total project cost.

Other benefits besides cost savings which support the decision to reduce external contractors are:

- Better response time for developer driven work
- Improved flexibility, more efficient work scheduling
- Consistent work practices and quality control

Table E4 – OEB 27 a) Construction

Description - Location	Total L+V+E	Total Cost	% L+V+E
Projects completed by External Contractor:			
Andover Trails Ph 2	40,611	121,001	33.6%
Beaverbrook Ph 6	139,610	625,295	22.3%
Hyde Pk W	23,735	70,159	33.8%
1059 Whetherfield Ph 2	13,391	43,667	30.7%
2295 Kains Rd	16,360	47,062	34.8%
Stone Crest	19,612	55,566	35.3%
AVERAGE	**42,220**	**160,458**	**31.7%**
Projects completed by Internal LH Labour:			
1625 Purser Ph 1	17,921	87,951	20.4%
Matthews Hall	34,407	163,005	21.1%
Riverbend Ph 6	27,556	99,365	27.7%
Kains West Ph 1	37,111	141,791	26.2%
Williamson subdivision	38,347	155,610	24.6%
Cameron Subd Ph 2	29,608	113,069	26.2%
Talbot Village Ph 2	33,071	120,531	27.4%
Northridge N Ph 4	27,142	95,155	28.5%
Hyde Park Meadows	105,700	462,233	22.9%
Woodholme Park	41,057	136,186	30.1%
1600 Mickleborough	35,459	88,185	40.2%
AVERAGE	**38,853**	**151,189**	**25.7%**

Information Services:

Information Services uses a mix of internal labour and external contractors to support both operating and capital activities. The additional internal full time equivalents ("FTE") which are part of the Executive Services department are described on Page 48-49 of Exhibit 4.

The following Table provides a comparison of 2013 internal labour rates and external contractor rates from London Hydro's preferred vendors. Preferred vendors were established based on an RFP process to ensure London Hydro received competitive bids from various sources and areas of expertise.

Table E4 – OEB 27 a) Information Services

Position	EXTERNAL RATE	INTERNAL RATE
SAP Specialists	$ 103.00	$ 73.19
GIS / OMS Project Manager	$ 150.00	$ 75.95
Business Analyst	$ 78.00	$ 65.02

NOTE 1: External Rate includes expenses
NOTE 2: London Hydro's Internal Rate is fully burdened and includes salary, benefits, and employee expenses

Benefits exist from the use of both internal labour and external contractors and London Hydro is optimizing the internal / external resource mix to meet growing functionality, complexity, and an integrated environment. This resource mix will ensure the cost of capital projects and operating activities are as low as possible, while at the same time continuing to meet requirements to effectively maintain and implement quality systems.

Other benefits of this resource mix are, among others:

- Critical mass of on-site staff augmented by specialized, external resources as required to resolve system issues in order to minimize customer impact.
- Optimal resource level with in-depth skills to satisfy the changing demands of on-going support and project work.
- Effective knowledge transfer i.e. leverage external resources to augment training of internal staff and leverage internal staff to reduce the business orientation, ramp up time of external resources.
- Provide staff continuity to address internal staff turnover.
- Enhance business acceptance of systems and improve quality with the right number of internal staff that know the business.
- Be ready to leverage emerging technologies such as smart grid, by utilizing internal and external resource's industry expertise.

b) A comparative analysis on the expenses included in OM&A is provided below for both Construction and Information Services. The mix to support OM&A activities

can change year to year depending on maintenance requirements and the availability of resources.

Construction:

Table E4 – OEB 27 b) Construction Resource Mix

Construction - Resource Mix in OM&A					
	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST
Contracted Labour	$ 202,670	$ 269,324	$ 176,537	$ 105,600	$ 126,100
Internal Labour	361,102	387,335	489,700	470,600	504,600
TOTAL	$ 563,772	$ 656,659	$ 666,237	$ 576,200	$ 630,700
TOTAL CHANGE:					
2009 - 2013 TEST ($)					$ 66,928
2009 - 2013 TEST (%)					11.9%
Annual Change ($)		$ 92,887	$ 9,578	$ (90,037)	$ 54,500
Annual Change (%)		16.5%	1.5%	-13.5%	9.5%
Change in CONTRACTED Labour 2010 - 2013 TEST ($)					$ (143,224)
Change in INTERNAL Labour 2010 - 2013 TEST ($)					$ 117,265
% Contracted Labour	35.9%	41.0%	26.5%	18.3%	20.0%
% Internal Labour	64.1%	59.0%	73.5%	81.7%	80.0%

Secondary cable repair efficiencies as discussed in part a) are reflected in the above change in resource mix in OM&A.

Information Services:

The Table and Chart below provides a comparative analysis for the expenses (OM&A) incurred between London Hydro's external contractors and London Hydro's forecasted expenses for internal resources for Information Services.

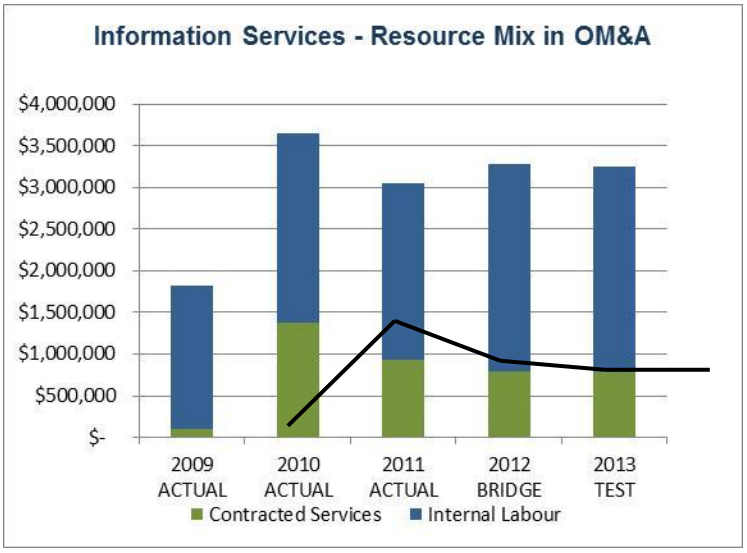
Since 2009, significant changes related to information systems and technology is impacting the total cost of resources required to support the new billing system, automated meter reading ("AMR") and time of use ("TOU") billing, and other systems such as Geographic Information Systems ("GIS") and the Outage Management System ("OMS"). Emerging technology and regulatory requirements and their impact are fully discussed in London Hydro's Strategic Plan (Exhibit 1, Appendix 1A) and the Information Technology Strategy (Exhibit 2, Appendix 2I). The above information should also be read in conjunction with the evidence related to OM&A provided in Exhibit 4.

London Hydro is moving to an optimal mix of approximately 76% internal labour and 24% external contracted labour for the on-going support and maintenance of information systems.

It is important to note that the significant business environment changes as discussion within Exhibit 4, within London Hydro's Strategic Plan (Exhibit 1, Appendix 1A), and in the response to the OEB's Interrogatory 26, above, all provide evidence related to these significant cost impacts. The resource mix for information services starting in 2010 is therefore more comparable once the new billing system implementation, the foundation for TOU billing, was complete. As shown below, contracted labour in the 2013 Test Year has declined $583,479 since the 2010 Actuals, and this reduction is only partially offset with increased internal labour in the amount of $213,379 for the same time period.

Table E4 – OEB 27 b) Information Services Resource Mix

Information Services - Resource Mix in OM&A					
	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST
Contracted Labour	$ 96,709	$ 1,370,279	$ 924,765	$ 786,800	$ 786,800
Internal Labour	1,722,533	2,275,621	2,120,151	2,541,164	2,489,000
TOTAL	$ 1,819,242	$ 3,645,901	$ 3,044,916	$ 3,327,964	$ 3,275,800
TOTAL CHANGE:					
2009 - 2013 TEST ($)					$ 1,456,558
2009 - 2013 TEST (%)					80.1%
Annual Change ($)		$ 1,826,659	$ (600,984)	$ 283,048	$ (52,164)
Annual Change (%)		100.4%	-16.5%	9.3%	-1.6%
Change in CONTRACTED Labour 2010 - 2013 TEST ($)					$ (583,479)
Change in INTERNAL Labour 2010 - 2013 TEST ($)					$ 213,379
% Contracted Labour	5.3%	37.6%	30.4%	23.6%	24.0%
% Internal Labour	94.7%	62.4%	69.6%	76.4%	76.0%



Maintenance Expense

Question OEB 28

Reference: Exh 4, p. 17 / Table 4-9,

The maintenance expense variance from 2010 to 2011 actual is $393,590 or 5.8%. The variance for the same expense from 2011 actual to 2012 bridge is $751,272 or 11.1%.

Please quantify and provide reasons for the large increase in variance from 2010 to 2011 actual compared to 2011 actual to 2012 bridge.

Response OEB 28:

The total maintenance expense variance from 2010 to 2011 Actual, and 2011 Actual to 2012 Bridge found in Table 4-9 on Page 17 is derived from numerous OEB accounts. The detailed year over year variances for each OEB account making up this total is provided in Table 4-42 (OEB Appendix 2-G) on Page 84, however the following Table is provided with variances at this detailed OEB account level for the two specific variances addressed in this question.

The primary driver of the variance increase between 2011 Actual and 2012 Bridge ($751,272 or 11.1%) is related to new maintenance costs for smart meters. Sensus RNI and Flexnet license and maintenance fees are included in OEB account 5175 – Maintenance of meters. This is a new incremental expense beginning in 2012 resulting from the implementation of smart meters. A full discussion of the new incremental smart meter operating and maintenance expense is provided in Exhibit 4, Pages 8 through 11.

As shown in Table E4-OEB 28 below, the total maintenance expense variance before the impact of smart meters is $524,172 or 7.7%. This variance is more appropriately compared to the 2010 to 2011 Actual variance of $393,590 or 5.8%. Maintenance consists of both planned and unplanned activities and can vary year over year depending on periodic audits, and other uncontrollable events, such as equipment failure and weather. The two year average variance in maintenance before the impact of smart meters is 7.2% per year.

The planned maintenance activity is primarily related to the recurring OEB audit and inspection effort which consistently costs approximately $230,000 per year. As a result of these inspections, certain maintenance and repair activities arise, and can vary from $300,000 to $400,000 per year depending on the audit findings. There are some other routine activities such as pole testing, infrared thermography inspections and graffiti removal although they are not a significant element of the planned maintenance activity.

Other maintenance costs can vary year over year and are purely re-active, or unplanned based on the number of actual outages experienced due primarily to equipment failures,

and storms. In 2012, there is higher maintenance of poles, line transformers, and underground conduit and lower maintenance related to underground conductors and devices.

The variances also reflect the addition of new Engineer positions. These positions are engaged in new operating and maintenance activities related to the development of London Hydro's Asset Sustainment Plan, GIS enhancements, the implementation of the new OMS, and the development of a number of distribution system planning activities. These new positions are also required as London Hydro's succession plan forecasts that five senior people will likely be retiring in the Engineering and Operations area over the next few years. Further discussion related to succession planning, employee demographics and changes in employee complement specifically related to Engineering and Operations can be found in Exhibit 4 starting on Page 36 and on Page 45 respectively.

Table E4 – OEB 28

OEB No	OEB Account Name	2010 Actual	2011 Actual	2012 Bridge	VARIANCES in OEB #28			
					2010 to 2011		2011 to 2012	
		CGAAP			$	%	$	%
5105	Maintenance supervision & engineering	1,242,742	1,420,801	1,648,298	178,058	14.3%	227,497	16.0%
5110	Maintenance of buildings & fixtures - distribution stations	44,335	92,967	66,053	48,632	109.7%	(26,914)	-28.9%
5114	Maintenance of distribution station equipment	217,687	296,775	262,203	79,088	36.3%	(34,572)	-11.6%
5120	Maintenance of poles, towers & fixtures	696,114	494,639	692,563	(201,475)	-28.9%	197,924	40.0%
5125	Maintenance of overhead conductors & devices	1,065,656	1,366,596	1,358,234	300,940	28.2%	(8,362)	-0.6%
5130	Maintenance of overhead services	177,095	207,094	188,518	29,999	16.9%	(18,576)	-9.0%
5135	Overhead distribution lines & feeders - right of way	647,810	785,017	882,700	137,207	21.2%	97,683	12.4%
5145	Maintenance of underground conduit	362,082	126,356	303,883	(235,726)	-65.1%	177,527	140.5%
5150	Maintenance of underground conductors & devices	880,178	1,125,571	912,040	245,393	27.9%	(213,531)	-19.0%
5155	Maintenance of underground services	485,985	521,033	491,780	35,048	7.2%	(29,252)	-5.6%
5160	Maintenance of line transformers	502,903	316,721	449,358	(186,183)	-37.0%	132,637	41.9%
5172	Sentinel Lights - Materials and Expenses	-	162	45	162	100.0%	(117)	-72.3%
5175	Maintenance of meters	66,007	28,453	277,781	(37,554)	-56.9%	249,328	876.3%
		6,388,593	6,782,183	7,533,455	393,590	5.8%	751,272	11.1%
REMOVE SMART METER IMPACT								
5175	Impact Related to Smart Meters (specifically Sensus and Flexnet RNI Licenses/Mtce)			(227,100)			(227,100)	-3.0%
		6,388,593	6,782,183	7,306,355	393,590	5.8%	524,172	7.7%

The preceding discussion excludes the impact of MIFRS.

Employee Expenses

Question OEB 29

Reference: Exh 4, pg. 40

London Hydro provided statistics on employee demographics as evidence of the on-going issue of an aging workforce. London Hydro noted that it is addressing this issue through supervisory, technical and specialized industry training as well as mentoring, and the hiring of new apprentice positions.

Does London Hydro align itself with local secondary and post-secondary educational institutions in order to increase the size of younger aged recruitment talent pool? If not, does London Hydro have any plans to do so? Please provide details.

Response OEB 29:

Yes. London Hydro has been active for a number of years with educational institutions through job fairs and recruiting of full time, co-op and internship positions. Western University, Fanshawe College, triOS College, and Westervelt are all located in the City of London and have provided great candidates to fill positions in IT, Engineering, Administration, and GIS. Positions filled as a result of this on-going relationship with local educational institutions include Help Desk Support, Engineers, Technicians, and Technologist.

London Hydro continues to post vacant positions at local post-secondary institutions and depending on the position; it has also posted at educational institutions specializing in training students with the skill set required.

London Hydro has participated in the co-op programs with both Conestoga College (Kitchener) and Cambrian College (Sudbury) to introduce and assess potential future full-time candidates from the Powerline Technician programs being offered at these colleges.

Question OEB 30

Reference: Exh 4, pg. 46

London Hydro has indicated that it has eliminated the VP, Customer Services and Strategic

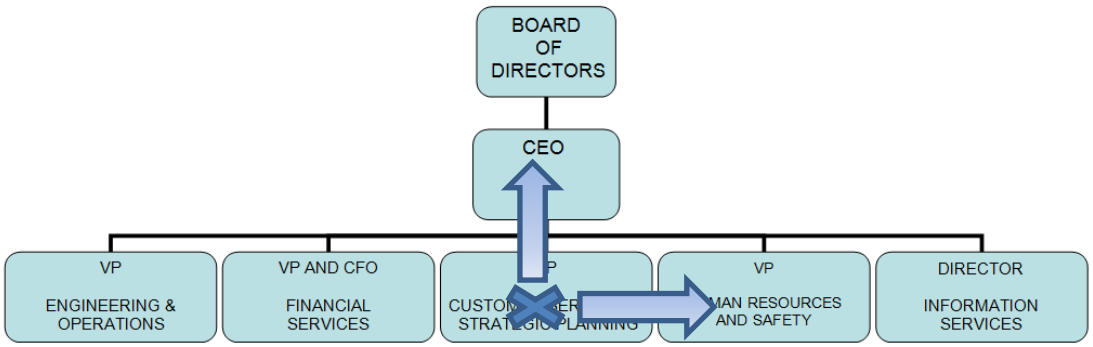
Planning.

If applicable, which position(s) has taken the responsibilities of the eliminated VP position? Is there a corresponding increase in salary or wages for this position or positions to compensate for additional responsibilities?

Response OEB 30:

The organization structure at London Hydro was previously comprised of five VP positions reporting to the Chief Executive Officer ("CEO") as shown in the chart below which was taken from the 2009 Rate Application to illustrate the shift in responsibilities.

2009 Organization Structure



As reported in the 2013 Rate Application, the VP, Customer Services and Strategic Planning position was eliminated. The Strategic Planning responsibilities were realigned to the CEO, and the responsibilities related to Customer Services were combined with the responsibilities of the existing VP, Human Resources and Safety. This VP position is now known as the VP, Corporate Services. There have been no corresponding increases in salaries at the VP level as a result of this re-organization.

A position at the management level was impacted by the downsizing of the VP position, and some responsibilities related to Human Resources were shifted. This resulted in the reclassification of one position and a corresponding increase in salary to compensate for additional responsibilities. The Manager, Human Resources was reclassified to Director, Human Resources.

Question OEB 31

Reference: Exh 4, pp. 45 and 49

London Hydro has indicated that under Engineering and Operations that three new Geographic Information Systems (GIS) positions will be required. Under Executive Services an addition of a GIS specialist will be required.

a) *Please provide an explanation as to how these roles differ.*

b) *Can any responsibilities and duties of these four positions be shared?*

Response OEB 31:

a) The three positions under Engineering and Operations are GIS Surveyor Technicians who provide the drafting services to draw, edit and maintain all of London Hydro's maps, drawings and data attributes for the Geographic Information Systems ("GIS"), the Outage Management System ("OMS"), standards, work order, and legacy paper drawings among others. They are the end-users of these systems.

   The position under Executive Services is a Project Manager, GIS/OMS and was referred to in the original submission as a "GIS Specialist". This position is part of the Information Services group and is responsible for the technical system support and on-going project management for both the GIS and OMS systems which are both based on Intergraph technology. The "GIS Specialist" position is accountable for the day-to-day GIS support and enhancements, the management of the multi-year OMS project implementation, and future day-to-day support and enhancements for that system.

b) The duties between the end-user positions within Engineering and Operations are most definitely shared, however the skill set and technical knowledge required to manage projects and support the technical aspects of both the GIS/OMS systems does not lend itself to job sharing with the system end-users. All positions will be working together to optimize the use of these system.

Question OEB 32

Reference: Exh 4, p. 69

It appears there is a large increase in Corporate Training and Employee Expenses from 2010 to 2011, $734,884 to $1,030,685 respectively. However in 2009 and 2010 London Corporate Training and Employee Expenses were below the $807,900 approved by the Board in 2009.

a) *Please explain the reasons for the reduction in Corporate Training and Employee Expenses for 2009 and 2010.*

b) *Please also explain what the major cost drivers to the large increase in Corporate Training and Employee Expenses from 2010 to 2011.*

c) *Does London Hydro expect to experience the same major cost drivers that London Hydro has indicated in interrogatory #32(b) for 2012 and 2013? If not, what adjustments could be made to the 2012 and 2013 Corporate Training and Employee Expenses?*

Response OEB 32:

a) Although the actual costs for Corporate Training and Employee Expenses for 2009 and 2010 were lower than the $807,900 approved by the Board in 2009 by $46,857 and $73,016 respectively, the total cost in this area was significantly higher than in prior years. The 2008 actual was $640,157. The 2009 actuals increased 18.9% over the preceding year reflecting the higher emphasis on employee development and training.

   The main contributor to the variance between the 2009 Board Approved amount and the actuals in 2009 and 2010 is related to spending for professional development conferences. Included in the total 2009 Board Approved budget for corporate training and employee expense was $158,200 for professional development conferences and related cost. The actuals in 2009 and 2010 was $89,014 and $69,186 respectively. London Hydro reduced spending in these areas as the benefits gained from the conferences did not justify the cost incurred.

Spending in the 2012 Bridge and the 2013 Test Years has been reduced to $94,700 for 2012 and then further reduced to $87,100 for 2013.

b) The major cost drivers impacting the increase from 2010 to 2011 are:

- Changes in technology and complexity requiring new skills and on-going sustainment and knowledge upgrades
- Regulatory compliance and specialized industry knowledge
- Succession planning, leadership development and apprentice and other skill trades training

The total expense related to corporate training and employee expense in 2011 was $1,030,685 an increase of $295,801 or 40.3% over the 2010 Actuals. In 2011 a new leadership training program was initiated which will continue into future years. London Hydro is building the strong supervisory and management skills required to work effectively in an environment of continual change and is also preparing for the forecasted loss of a significant number of experienced and knowledgeable staff who are approaching retirement. Succession planning is also continuing to impact the level of apprenticeship training that occurred in 2011 and will be required in subsequent years.

c) Yes, London Hydro expects to experience the same major cost drivers in 2012, 2013, and beyond.

Meter Reading Expenses

Question OEB 33

References: Exh 4, p. 59; Excel Appendix 2-G

London Hydro's forecast of Meter Reading Expense (Account 5310) is $1,248,848, which is approximately $220,000 less than the actual cost in 2010. The forecast of a purchase of Contract Meter Reading Service in Exhibit 4, p. 59, is $700,000, which is approximately the same saving compared to the 2010 amount.

a) Does the reduction of meter reading cost from 2010 to 2013 reflect the full savings

that would be expected from full implementation of Smart Meters during that time, or does the 2013 forecast assume only partial savings from Smart Meters?

b) *Please provide a breakdown of the number of Meter Reader positions before London Hydro's smart meter deployment and the current number of Meter Reader positions today.*

Response OEB 33:

a) Yes, the reduction of meter reading cost from 2010 to 2013 reflects the full savings that would be expected from the full implementation of Smart Meters. The $700,000 contracted meter reading service in Exhibit 4, page 59 is primarily (92%) related to the reading of water meters, with only 8% or $56,000 related to obtaining electric meter readings. London Hydro does recover 100% of the meter reading costs related to the water meter readings from the City of London. Costs and the recovery of cost related to water meter reading is netted within OEB Account 5310 – Meter Reading Expense.

b) London Hydro's smart meter deployment was fully completed in January 2011, however the move to automated meter readings from the traditional meter reading methods was phased in during the second half of 2010.

During this transition in 2010, London Hydro had 2 meter reader positions on staff. At the time of this writing, there is only one meter reader position remaining.

Environmental Expense

Question OEB 34

Reference: Exh 4, p.75

London Hydro indicated that it is addressing an issue with lead contamination in its facilities and vehicles which requires clean-up and secure, safe place to store and work on lead. London Hydro indicated that at the time of writing the application, this work was nearing completion and that costs are expected to approach $120,000 or twice the amount of the original forecast.

a) *Please provide a status update with regards to the progress of this work.*

b) Please explain why the actual costs are expected to be double the amount of the original forecast.

c) Is the cost of the remediation program included in the test year revenue requirement, as the remainder of the program's cost or as a recurring expense?

Response OEB 34:

a) The clean-up and confirmatory swab testing was completed by the end of December 2012. As explained below the clean-up involved three rounds of cleaning each lowering the size and concentration level of the lead contamination. At the end of 2012 all known areas within the general work environment at London Hydro's 111 Horton Street facility and work vehicles have been cleaned up to a level under the acceptable lead levels for non-residential areas. Certain designated 'Lead Contaminated' areas will remain with appropriate signage, security and safe work practices in place to protect the staff, public and the environment.

b) The scope of the areas requiring cleaning was based on past knowledge of the storage and use of lead products in certain London Hydro Sub Stations, Electrical Underground Systems ("EUS") and Substation Maintenance departments, as well as an initial set of sample swab tests completed by London Hydro's consulting engineering firm. The initial price was based on cleaning the known contaminated areas as well as areas found in the initial set of swab tests. An initial clean-up was conducted with confirmatory swab testing following immediately after the first round of cleaning. These second set of swab tests indicated that the contamination was wider spread than first indicated. The decision was made to expand clean-up to include the entire Sub Station Maintenance department and an open mezzanine storage area above the department's workshop area. A further clean-up was conducted within the larger defined area with confirmatory swab testing following immediately after this second round of cleaning.

The follow up set of swab tests indicated certain areas requiring further spot cleaning in 4 Sub Stations and a few very localized areas within the EUS and Substation Maintenance Departments. The third round on cleaning and swab testing was completed late in December 2012.

It is anticipated the total project cost will be approximately $240,000, which is significantly higher than original estimates and impacted by the findings as the project clean-up evolved.

c) The cost of the lead remediation project completed in 2012 and described above is not specifically included in the 2013 Test Year revenue requirement; however, various environmental projects are planned for 2013 and beyond. Environmental expense is recurring in nature, although the specific project, its scope, remediation requirements, and timing changes year to year. Often the extent of the remediation required cannot be predicted even when utilizing experts in the field who analyze related information and samples from the sites under review.

Please refer to Exhibit 4, Page 75, for commentary related to remediation projects and locations planned for 2013 and beyond starting on Line 12. London Hydro has included $60,000 as part of OM&A in the 2013 Test Year for these recurring environmental expenses.

Cost Recovery

Question OEB 35

References: Exh 4, pp. 77 and 102

In Exhibit 4 the forecast cost recovery from London Hydro's services provided to the City of London for water billing is described at p. 77, with a forecast amount of $3,950,000. At p. 102, forecast price is shown at $3,750,000, against an incremental cost of $1,030,000.

a) *Please explain which of the cost recovery amounts in Exhibit 4 is correct, i.e. p. 77 or p. 102. Alternatively, please explain the distinction between London Hydro's activities that result in these two different amounts.*

b) *Please confirm that London Hydro's base revenue requirement in this application is lower than it would be if London Hydro did not provide water billing services, and that this amount (based on the information at Exhibit 4, p. 102) is forecast to be $3,750,000 less $1,030,000.*

Response OEB 35:

a) The cost recovery in the 2013 Test Year for London Hydro's services provided to the City of London for water billing is $3,750,000. This is based on the independent consultant report completed by Navigant Consulting Inc. and is based on the fully allocated cost pricing methodology.

The discrepancy between Page 77 and Page 102 of Exhibit 4 was previously identified by London Hydro and an explanation was provided in the Application Addendum documents filed on October 26, 2012. Please refer to Addendum #2 and #3 for further information.

b) London Hydro confirms that the base revenue requirement in this Application is lower than it would be if London Hydro did not provide water billing services to the City of London and that the revenue requirement is lower by $2,720,000 ($3,750,000 less $1,030,000).

Within the independent consultant report, the avoided cost if London Hydro no longer provided this service was identified as $1,030,000. This is the amount London Hydro would shed if it were to no longer provide these services to the City of London. In other words as shown in the Table below, an increase of $2,720,000 in revenue requirement would be required if the City of London procured the water billing services from another source. The electric rate payers would be adversely impacted if that occurred.

Table - E4 OEB 35

Loss of Water Billing Contract - Impact to Revenue Requirement	2013 TEST Year
Cost Recovery from Water Billing Services	$ 3,750,000
Avoidable Cost if LH no longer provides service	(1,030,000)
Increase in Revenue Requirement	$ 2,720,000

Copper Theft

Question OEB 36

Reference: Exh 4, p. 80

London Hydro has indicated a variance of $301,000 between 2010 and 2011 actual 5125 Maintenance of Overhead Conductors and Devices. London Hydro indicated that a very large number of copper ground wires were missing on poles due to theft.

Has this trend continued? If so, does London Hydro have a plan to prevent the theft of its copper ground wires? Please explain.

Response OEB 36:

The amount of theft of copper varies year over year but it is certainly higher now than a decade ago. Incidences of theft are directly connected to the higher commodity prices as well as changing economic factors.

To reduce and/or prevent theft London Hydro has taken the following measures:

1. replaced stolen grounds with copper clad steel ground wire, which has a minimal scrap value and is significantly harder to cut and remove
2. labelled the new copper clad wire in substations with an 8 x 8 cm tag that says “No Scrap Value”, and
3. installed internet cameras and security signage at key substations
4. prosecute offenders whenever possible

Issue 4.2 Is the proposed forecast of the Depreciation/Amortization expense for the 2013Test Year appropriate?

Depreciation

Question OEB 37

Reference: Exh 4, p. 114

London Hydro has chosen a useful life of 75 years for 1805 – Substation Building. The Kinectrics report provided a Typical Useful Live (TUL) of 50 years for London Hydro.

a) *Does London Hydro find it reasonable to increase the TUL of the substation building by 50% of what the Kinectrics report provided?*

b) *Please provide the updated depreciation expense and accumulated amortization if London Hydro used the 50 years by Kinectrics.*

Response OEB 37:

a) Yes, based on the construction methods used and their condition, London Hydro finds it reasonable to increase the TUL of substation buildings to 75 years.

The Kinectrics report includes a typical range of 30 to 80 years, however, based on professional knowledge and experience related specifically to the assets owned and managed by London Hydro, the high end of the range is most appropriate. As an example, London Hydro has 4 substation buildings built between 1950 and 1960 which are over 50 years old that are not scheduled for replacement in the foreseeable future.

b) The following Table provides the updated depreciation expense and accumulated amortization if the TUL for substation buildings was 50 years for both 2012 and 2013. To summarize if the TUL was revised it would result in an annual increase in depreciation expense in the amount of $7,554. The accumulated amortization would also be higher in the same amount annually.

Table – E4 OEB 37

OEB Object 1808 - Substation Buildings	Original Submission (75 yr)	Revised TUL (50 yr)	Difference
2012 - MIFRS			
Cost			
31-Dec-11	1,128,336	1,128,336	-
2012 Additions	75,000	75,000	-
31-Dec-12	1,203,336	1,203,336	-
Accumulated Amortization			
31-Dec-11	685,092	685,092	-
2012 Depreciation Expense	17,772	25,326	7,554
31-Dec-12	702,864	710,418	7,554
Net Book Value			
31-Dec-12	500,472	492,918	(7,554)
2013 - MIFRS			
Cost			
31-Dec-12	1,203,336	1,203,336	-
2013 Additions	75,000	75,000	-
31-Dec-13	1,278,336	1,278,336	-
Accumulated Amortization			
31-Dec-12	702,864	710,418	7,554
2013 Depreciation Expense	12,592	19,896	7,304
31-Dec-13	715,456	730,314	14,858
Net Book Value			
31-Dec-13	562,880	548,022	(14,858)

There would be a small increase to the Transition to MIFRS (OEB 1575) if this lower TUL was adopted totalling $7,554 in the transition year (2012).

Question OEB 38

Reference: Exh 4, p. 125

London Hydro has indicated a Grand Total Depreciation Expense of $16,859,795 under CGAAP for 2011.

Please reconcile this amount with the depreciation amount found in London Hydro's 2011 annual report. If there is a variance, please provide reasons for the variance.

Response OEB 38:

Table E4 – OEB 38 is provided below to identify the reasons and reconcile the difference in the Total 2011 Depreciation Expense under CGAAP as presented in Table 4-57 (OEC Appendix 2-CE) found on Page 125 of Exhibit 4. For external financial reporting purposes, depreciation includes amounts related to vehicles and equipment. For rate making purposes this is included as part of the total OM&A using overhead allocations. London Hydro has also removed the depreciation related to the non-distribution renewable generation assets for rate making purposes as per the Filing Requirements.

Table - E4 OEB 38

Reconciliation Between External Financial Statements and Depreciation in Rate Application (2011)		
LH External Financial Statements		**17,669,346**
ADJUSTED FOR:		
Remove V&E depreciation	- reported as part of OM&A for RA, as fleet expenses are allocated to various OEB OM&A and capital accounts	(777,730)
Remove depreciation expense related to Renewable generation assets	- non distribution, therefore should be excluded for rate making purposes	(31,821)
Depreciation Expense in RA - Exh 4, page 125		**16,859,795**

LRAM for pre-2011 CDM Activities

Question OEB 39

References:

i. *Exh 4, p. 136*

ii. *Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13, LRAM*

London Hydro notes that the Board approved in its 2012 IRM rate application, the recovery of an LRAM claim for 2010 CDM activity in 2010. London also notes that it intends to file for recovery of persistent 2010 lost revenues in 2011 and 2012 in its 2014 IRM rate application. London Hydro indicated that it opted to wait until its 2014 rate application to file for recovery of these amounts because of the delay in receiving the final OPA evaluation CDM report for

2011. London further cites rate mitigation as a factor in its request to defer the recovery of persisting lost revenues from pre-2011 CDM programs.

Board staff notes that section 13.6 of the 2012 CDM Guidelines state that it is the Board's expectation that LRAM for pre-2011 CDM activities should have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

The Board also noted that SSM for pre-2011 CDM activities should be completed with the 2012 rate applications and that SSM is not applicable for savings persisting from prior years.

As London Hydro has not included a request for recovery of persisting LRAM amounts from 2010 programs in 2011 and 2012, Board staff seeks the following information.

a) *Please discuss if London has received its final 2011 OPA results. If London has received its final 2011 OPA results, please provide them.*

b) *Please confirm that London will be relying on final 2006-2010 OPA CDM program results when calculating the lost revenues from persisting 2010 CDM program savings in 2011 and 2012. If this is not London's understanding, please discuss.*

c) *Please discuss the rationale for not recovering the remaining LRAM amounts from the persisting CDM savings of 2010 programs in 2011 and 2012 even though the Board has instructed distributors to do so.*

d) *Please provide full LRAM calculations for persisting 2010 CDM savings that are still outstanding. Please use the 2008 CDM Guidelines (EB-2008-0037) when preparing your LRAM claim for lost revenues associated with pre-2011 CDM programs.*

Response OEB 39

a) London Hydro has now received its OPA report on the final 2011 OPA CDM program results.

Please find a copy of the OPA report file as Excel document and identified as "LondonHydro_ Copy of 2011_Final_Annual_Report_Data_CDM_OPAPrograms_20130108".

b) London Hydro confirms that London Hydro will be relying on final 2006-2010 OPA CDM program results in 2011 and 2012.

c) As reflected in Exhibit 4 page 136, and as indicated by Board staff in their question 39:

"London Hydro notes that the Board approved in its 2012 IRM rate application, the recovery of an LRAM claim for 2010 CDM activity in 2010. London also notes that it intends to file for recovery of persistent 2010 lost revenues in 2011 and 2012 in its 2014 IRM rate application. London Hydro indicated that it opted to wait until its 2014 rate application to file for recovery of these amounts because of the delay in receiving the final OPA evaluation CDM report for 2011. London further cites rate mitigation as a factor in its request to defer the recovery of persisting lost revenues from pre-2011 CDM programs".

London Hydro's intent was to file its LRAM recovery rate application to recover 2011 and 2012 lost distribution revenues due to persistent 2010 CDM programs funded by the OPA in its 2014 IRM Rate Application, due to the inability to obtain a final OPA CDM program results report for 2011.

However, as Board staff have requested the filing of the LRAM claim for lost revenues associated with pre-2011 CDM program, and London Hydro is now in the possession of the final evaluation 2011 OPA CDM program results, London Hydro will file a LRAM claim with this Application seeking Board's consideration for the recovery of lost revenues from CDM activates per-2011.

d) Please find London Hydro's LRAM recovery rate application contained in APPENDIX B: 2013 Lost Revenue Adjustment Mechanism ("LRAM") Recoveries Rate Application Persistence of 2010 OPA CDM Program.

London Hydro is applying to the Board for the approval to recover a LRAM amount of $266,877.56, including carrying costs.

It should be clarified that London Hydro did consider applying for LRAM for CDM Program Results as contained in the 2011 CDM OPA report (file as Excel document and identified as "LondonHydro_ Copy of 2011_Final_Annual_Report_Data_CDM_OPAPrograms_20130108"). In particular, amounts related to Pre-2011 Programs completed in 2011 (as reflected in the table below).

Table 5: Summarized Program Results

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Pre-2011 Programs completed in 2011											
22	Electricity Retrofit Incentive Program	94%	95%	2,288	16,207,519	60%	60%	1,359	9,726,531	1,359	38,906,125
23	High Performance New Construction	100%	100%	337	1,731,809	50%	50%	169	865,905	169	3,463,618
24	Toronto Comprehensive	-	-	0	0	-	-	0	0	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0	0	0

Assumes demand response resources have a persistence of 1 year

London Hydro took into consideration that these results are 2010 carry-over projects and are those approved under the OPA 2010 rules and incentive levels, but actually carried out in 2011. It would be inappropriate for London Hydro to record these program results for 2010 LRAM application and therefore the savings are not included in this 2010 LRAM filing. However, these results do count towards London Hydro's 2011 - 2014 CDM targets.

Cost Allocation (Exhibit 7)

Cost Allocation – Unmetered Scattered Load "USL"

Question OEB 40

Reference: Cost Allocation Model, worksheets I 6.2 'Customer Data' and I 8 'Demand Data'

a) *Please clarify the number of USL customers and connections, and the frequency of customer billing. In particular, if London Hydro is forecasting that it will issue 2027 bills to customers in this class during the year, how does this reconcile with the information provided on the number of customers in this class.*
b) *Please confirm that the load profile of Bus Shelters is established by using the calculated hours of use, and that Traffic Signals are established by wattage times 24 hours per day (rather than vice versa as described in London Hydro's Conditions of Service at pp. 60-61).*
c) *Please describe the other significant loads that are included in the USL class and explain:*
    i. *how their load profiles have been established, and*
    ii. *whether any of these loads have a temperature-sensitive or seasonal component in their load profile.*

Response OEB 40

a) The number of customers for the Unmetered Scattered Load ("USL") customer class is 55. The number of connections is 1,544 as reflected in the Cost Allocation Model worksheet I6.2 "Customer Data". The frequency of the billing to the Unmetered Scattered Load customer class is monthly.

The forecasting figure of 2,027 bills to be issued does not equate with the above data. It appears that adjustments need to be made as a result of an improper formula which was included in cell L17 of the Cost Allocation Model worksheet I6.2

"Customer Data" and that consideration that London Hydro applies USL billings on some of the other Customer non-USL class billings that are issued.

In the cell L17 includes an incorrect formula that multiplies the number of connections by a factor 1.3125, resulting in an error as to the number of bills. This error in the resulting number of bills appears to be unique to the USL class. Further, although we have 55 customers' accounts, there are 16 USL customers who have their USL bills recorded on another non-USL service billing. Thus to reduce duplicate billing factor in the Cost Allocation Model, the USL customer count (billed) that should be reflected is 39 (55 customer count subtract 16 customers who have USL billing activity applied to non-USL billing).

Therefore, the correct forecast for the number of bills to be issued to the USL customer class is 468 (frequency of billing 12 X number of customers who have separate USL billing 39) and not 2,027 as reflected in cell L17 of the Cost Allocation Model worksheet I6.2 "Customer Data" of the Application model.

The following Tables reflect the error and the correction to L17 of the Cost Allocation Model worksheet I6.2 "Customer Data":

Original Application Filing:

L17 =+L19*1.3125

Sheet I6. 2 Customer Data Worksheet - Final Run

	ID	Total	1 Residential	2 GS <50	3 GS 50 to 4,999 kW	5 Co Generation	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$1,372,422	$1,111,316	$197,206	$63,900	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$1,215,006	$716,968	$203,733	$292,928	$0	$1,377	$0	$0	$0
Number of Bills	CNB	1,781,065	1,613,582	143,297	19,446	36	36	12	2,629	2,027
Number of Devices								35,004		
Number of Connections (Unmetered)	CCON	18,641						16,416	681	1,544
Total Number of Customers	CCA	153,868	138,004	11,970	1,662	3	3	1	681	1,544
Bulk Customer Base	CCB	-								
Primary Customer Base	CCP	153,868	138,004	11,970	1,662	3	3	1	681	1,544
Line Transformer Customer Base	CCLT	153,728	138,004	11,968	1,528	2	-	1	681	1,544
Secondary Customer Base	CCS	152,260	138,004	11,968	62	-	-	1	681	1,544
Weighted - Services	CWCS	167,605	138,004	17,952	465	-	-	9,850	409	926
Weighted Meter -Capital	CWMC	19,836,486	11,038,319	6,309,953	2,398,776	44,719	44,719	-	-	-
Weighted Meter Reading	CWMR	2,129,018	1,616,568	143,544	365,378	1,764	1,764	-	-	-
Weighted Bills	CWNB	1,886,660	1,613,582	143,297	126,399	540	540	12	263	2,027

Adjusted:

Sheet I6.2 Customer Data Worksheet - Final Run

	ID	Total	1 Residential	2 GS <50	3 GS 50 to 4,999 kW	5 Co Generation	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$1,372,422	$1,111,316	$197,206	$63,900	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$1,215,006	$716,968	$203,733	$292,928	$0	$1,377	$0	$0	$0
Number of Bills	CNB	1,779,506	1,613,582	143,297	19,446	36	36	12	2,629	468
Number of Devices								35,004		
Number of Connections (Unmetered)	CCON	18,641						16,416	681	1,544
Total Number of Customers	CCA	153,868	138,004	11,970	1,662	3	3	1	681	1,544
Bulk Customer Base	CCB	-								
Primary Customer Base	CCP	153,868	138,004	11,970	1,662	3	3	1	681	1,544
Line Transformer Customer Base	CCLT	153,728	138,004	11,968	1,528	2	-	1	681	1,544
Secondary Customer Base	CCS	152,260	138,004	11,968	62	-	-	1	681	1,544
Weighted - Services	CWCS	167,605	138,004	17,952	465	-	-	9,850	409	926
Weighted Meter -Capital	CWMC	19,836,486	11,038,319	6,309,953	2,398,776	44,719	44,719	-	-	-
Weighted Meter Reading	CWMR	2,129,018	1,616,568	143,544	365,378	1,764	1,764	-	-	-
Weighted Bills	CWNB	1,885,101	1,613,582	143,297	126,399	540	540	12	263	468

The following Tables reflect the resulting adjustments of the USL billing number change to worksheet "O1 Rev to Cost RR" of the Cost Allocation Model:

Original Application Filing:

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS 50 to 4,999 kW	5 Co Generation	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
crev	Distribution Revenue at Existing Rates	$53,355,018	$36,037,050	$7,785,060	$12,045,905	$274,161	$1,606,434	$1,043,340	$46,684	$84,251	$366,133
mi	Miscellaneous Revenue (mi)	$3,397,982	$2,091,150	$470,048	$691,791	$5,842	$36,940	$75,794	$3,168	$7,453	$15,790
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	$62,753,000	$38,188,200	$8,255,107	$12,737,696	$280,003	$1,643,374	$1,125,134	$49,853	$91,710	$381,923
	Factor required to recover deficiency (1 + D)	1.1081									
	Distribution Revenue at Status Quo Rates	$65,770,373	$39,998,580	$8,626,504	$13,347,881	$303,794	$1,780,064	$1,162,758	$51,730	$93,357	$405,706
	Miscellaneous Revenue (mi)	$3,397,982	$2,091,150	$470,048	$691,791	$5,842	$36,940	$75,794	$3,168	$7,453	$15,790
	Total Revenue at Status Quo Rates	$69,168,355	$42,089,730	$9,096,551	$14,039,671	$309,636	$1,817,004	$1,238,552	$54,899	$100,816	$421,496
	Expenses										
di	Distribution Costs (di)	$15,566,232	$8,134,046	$2,130,787	$4,181,781	$62,372	$402,424	$416,960	$17,249	$40,453	$180,161
cu	Customer Related Costs (cu)	$5,686,628	$4,388,205	$740,219	$547,155	$4,061	$4,061	$15	$335	$2,578	$0
ad	General and Administration (ad)	$12,591,657	$7,383,611	$1,707,292	$2,817,197	$39,753	$242,228	$251,908	$10,610	$25,888	$107,169
dep	Depreciation and Amortization (dep)	$15,788,219	$8,407,978	$2,436,212	$3,915,290	$53,345	$338,384	$427,038	$17,672	$41,065	$145,235
INPUT	PILs (INPUT)	$334,484	$502,445	$139,183	$230,837	$3,604	$13,341	$26,510	$1,037	$2,554	$8,313
INT	Interest	$8,648,455	$4,650,021	$1,288,111	$2,136,353	$33,356	$184,551	$245,345	$10,149	$23,636	$76,934
	Total Expenses	$59,215,674	$33,472,306	$8,441,803	$13,828,614	$202,491	$1,191,589	$1,367,776	$57,111	$136,174	$517,811
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$3,952,634	$5,351,240	$1,482,356	$2,458,513	$38,386	$212,382	$282,342	$11,679	$27,200	$88,536
	Revenue Requirement (includes NI)	$69,168,355	$38,823,593	$9,924,160	$16,287,127	$240,877	$1,403,970	$1,650,118	$68,789	$163,374	$606,347
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$381,356,639	$202,367,225	$54,949,680	$97,501,563	$1,506,954	$8,830,438	$10,924,129	$451,942	$1,052,099	$3,772,610
gp	General Plant - Gross	$40,103,063	$14,875,927	$3,245,592	$18,250,623	$97,398	$1,652,313	$1,126,558	$46,515	$108,660	$705,475
accum dep	Accumulated Depreciation	($194,084,396)	($102,714,745)	($27,624,702)	($49,905,664)	($774,037)	($4,685,501)	($5,585,317)	($231,094)	($537,733)	($2,026,202)
	Total Net Plant	$227,380,706	$114,528,407	$30,570,570	$65,846,522	$830,314	$5,797,250	$6,465,370	$267,363	$623,026	$2,451,883
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$335,766,210	$110,392,922	$40,107,713	$157,976,140	$4,284,146	$19,963,281	$2,446,427	$79,715	$509,865	$0
	OM&A Expenses	$33,844,516	$19,311,861	$4,578,298	$7,546,133	$106,185	$648,712	$668,883	$28,134	$68,919	$287,329
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$369,610,726***	***$129,704,783***	***$44,686,011***	***$165,522,274***	***$4,390,332***	***$20,611,994***	***$3,115,310***	***$107,849***	***$578,783***	***$287,329***
	Working Capital	$42,209,545	$14,880,806	$5,103,142	$18,902,644	$501,376	$2,354,575	$355,768	$12,323	$66,097	$32,813
	Total Rate Base	$269,590,259	$129,409,213	$35,673,712	$84,749,166	$1,331,690	$8,151,825	$6,821,138	$279,686	$689,123	$2,484,696
		Rate Base Input equals Output									
	Equity Component of Rate Base	$107,836,104	$51,763,689	$14,269,485	$33,899,666	$532,676	$3,260,730	$2,728,455	$111,874	$275,649	$993,878
	Net Income on Allocated Assets	$9,913,107	$8,617,424	$654,748	$211,057	$107,145	$625,415	($129,224)	($2,212)	($35,358)	($135,888)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$9,913,107	$8,617,424	$654,748	$211,057	$107,145	$625,415	($129,224)	($2,212)	($35,358)	($135,888)
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	100.00%	108.41%	91.66%	86.20%	128.55%	129.42%	75.06%	79.81%	61.71%	69.51%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($6,415,350)	($635,393)	($1,669,052)	($3,543,431)	$38,126	$239,403	($524,984)	($18,937)	($71,664)	($224,424)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$3,266,137	($827,608)	($2,247,456)	$68,759	$413,034	($411,566)	($13,891)	($62,558)	($184,851)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.19%	16.65%	4.59%	0.62%	20.11%	19.18%	-4.74%	-1.98%	-12.83%	-13.67%

Adjusted:

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS 50 to 4,999 kW	5 Co Generation	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
crev	Distribution Revenue at Existing Rates	$59,355,018	$36,097,050	$7,785,060	$12,045,905	$274,161	$1,606,434	$1,043,340	$46,684	$84,251	$366,133
mi	Miscellaneous Revenue (mi)	$3,397,982	$2,091,297	$470,061	$691,802	$5,842	$36,340	$75,794	$3,168	$7,288	$15,790
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	$62,753,000	$38,188,346	$8,255,120	$12,737,707	$280,003	$1,643,374	$1,125,134	$49,853	$91,539	$381,923
	Factor required to recover deficiency (1 + D)	1.1081									
	Distribution Revenue at Status Quo Rates	$65,770,373	$39,998,580	$8,626,504	$13,347,881	$303,794	$1,780,064	$1,162,758	$51,730	$93,357	$405,706
	Miscellaneous Revenue (mi)	$3,397,982	$2,091,297	$470,061	$691,802	$5,842	$36,340	$75,794	$3,168	$7,288	$15,790
	Total Revenue at Status Quo Rates	$69,168,355	$42,089,876	$9,096,564	$14,039,682	$309,636	$1,817,004	$1,238,552	$54,899	$100,645	$421,496
	Expenses										
di	Distribution Costs (di)	$15,566,232	$8,134,046	$2,130,787	$4,181,781	$62,372	$402,424	$416,360	$17,249	$40,453	$180,161
cu	Customer Related Costs (cu)	$5,686,628	$4,389,902	$740,369	$547,288	$4,061	$4,061	$15	$335	$536	$0
ad	General and Administration (ad)	$12,591,657	$7,390,573	$1,707,378	$2,817,273	$33,753	$242,229	$251,308	$10,611	$24,764	$107,169
dep	Depreciation and Amortization (dep)	$15,788,219	$8,407,378	$2,436,212	$3,915,280	$59,345	$338,384	$427,038	$17,672	$41,065	$145,235
INPUT	PILs (INPUT)	$934,484	$502,445	$139,183	$230,837	$3,604	$19,341	$26,510	$1,097	$2,554	$8,313
INT	Interest	$8,648,455	$4,650,021	$1,288,111	$2,136,353	$33,356	$184,551	$245,345	$10,149	$23,636	$76,934
	Total Expenses	$59,215,674	$33,474,366	$8,442,039	$13,828,822	$202,492	$1,191,590	$1,367,776	$57,111	$133,067	$517,811
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$3,952,634	$5,351,240	$1,482,356	$2,458,513	$38,386	$212,382	$282,342	$11,679	$27,200	$88,536
	Revenue Requirement (includes NI)	$69,168,355	$38,826,252	$9,924,396	$16,287,335	$240,878	$1,403,971	$1,650,118	$68,790	$160,268	$606,347
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$381,356,639	$202,367,225	$54,943,680	$97,501,563	$1,506,954	$8,830,438	$10,924,129	$451,942	$1,052,099	$3,772,610
gp	General Plant - Gross	$40,103,063	$14,875,927	$3,245,532	$16,250,623	$97,338	$1,652,313	$1,126,558	$46,515	$108,660	$705,475
accum dep	Accumulated Depreciation	($194,084,396)	($102,714,745)	($27,624,702)	($49,305,664)	($774,037)	($4,685,501)	($5,585,317)	($231,094)	($537,733)	($2,026,202)
	Total Net Plant	$227,380,706	$114,528,407	$30,570,570	$65,846,522	$830,314	$5,797,250	$6,465,370	$267,363	$623,026	$2,451,883
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$335,766,210	$110,392,322	$40,107,713	$157,376,140	$4,284,146	$13,963,281	$2,446,427	$79,715	$503,865	$0
	OM&A Expenses	$33,844,516	$13,314,521	$4,578,534	$7,546,342	$106,186	$648,713	$668,883	$28,194	$65,812	$287,329
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$369,610,726***	***$150,307,443***	***$44,686,247***	***$165,522,482***	***$4,390,333***	***$20,617,995***	***$3,115,310***	***$107,910***	***$575,677***	***$287,329***
	Working Capital	$42,209,545	$14,881,110	$5,103,169	$18,902,667	$501,376	$2,354,575	$355,768	$12,323	$65,742	$32,813
	Total Rate Base	$269,590,253	$129,409,525	$35,673,739	$84,749,189	$1,331,690	$8,151,825	$6,821,138	$279,686	$688,769	$2,484,696
		Rate Base Input equals Output									
	Equity Component of Rate Base	$107,836,104	$51,763,810	$14,269,496	$33,899,676	$532,676	$3,260,730	$2,728,455	$111,874	$275,507	$993,878
	Net Income on Allocated Assets	$3,313,107	$8,614,911	$654,525	$210,860	$107,144	$625,415	($129,224)	($2,212)	($32,422)	($135,888)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$3,313,107	$8,614,911	$654,525	$210,860	$107,144	$625,415	($129,224)	($2,212)	($32,422)	($135,888)
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	100.00%	108.41%	91.66%	86.20%	128.54%	129.42%	75.06%	79.81%	62.80%	69.51%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($6,415,350)	($637,906)	($1,669,276)	($3,549,628)	$38,125	$239,402	($524,984)	($18,937)	($68,726)	($224,424)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$3,263,624	($827,832)	($2,247,653)	$68,758	$413,033	($411,566)	($13,891)	($59,622)	($184,851)
	RETURN ON EQUITY COMPONENT OF RATE BASE	3.19%	16.64%	4.59%	0.62%	20.11%	13.18%	-4.74%	-1.98%	-11.77%	-13.67%

Original Filed Appendix 2-P

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from 2009 Study	%	Costs Allocated in 2013 Test Year Study (Column 7A)	%
Residential	$ 31,448,713	57.57%	$ 38,823,593	56.13%
GS < 50 kW	$ 6,897,739	12.63%	$ 9,924,160	14.35%
GS > 50 kW < GS < 4,999 kW	$ 13,083,386	23.95%	$ 16,287,127	23.55%
GS 50 to 4,999 kW (Co-Generation)	$ 102,943	0.19%	$ 240,877	0.35%
Large Use >5MW	$ 1,148,208	2.10%	$ 1,403,970	2.03%
Street Light	$ 1,366,580	2.50%	$ 1,650,118	2.39%
Sentinel	$ 73,669	0.13%	$ 68,789	0.10%
Unmetered Scattered Load	$ 186,056	0.34%	$ 163,374	0.24%
Standby	$ 317,015	0.58%	$ 606,347	0.88%
Total	$ 54,624,309	100.00%	$ 69,168,355	100.00%

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C L.F. X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 36,097,050	$ 39,998,580	$ 36,984,049	$ 2,091,150
GS < 50 kW	$ 7,785,060	$ 8,626,504	$ 9,454,112	$ 470,048
GS > 50 kW < GS < 4,999 kW	$ 12,045,905	$ 13,347,881	$ 15,595,336	$ 691,791
GS 50 to 4,999 kW (Co-Generation)	$ 274,161	$ 303,794	$ 235,035	$ 5,842
Large Use >5MW	$ 1,606,434	$ 1,780,064	$ 1,507,428	$ 36,940
Street Light	$ 1,049,340	$ 1,162,758	$ 1,326,806	$ 75,794
Sentinel	$ 46,684	$ 51,730	$ 58,742	$ 3,168
Unmetered Scattered Load	$ 84,251	$ 93,357	$ 139,577	$ 7,459
Standby	$ 366,133	$ 405,706	$ 469,288	$ 15,790
Total	$ 59,355,018	$ 65,770,372	$ 65,770,372	$ 3,397,982

1 + d	1.1081

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2010	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	108.10	108.41	100.65	85 - 115
GS < 50 kW	108.80	91.66	100.00	80 - 120
GS > 50 kW < GS < 4,999 kW	80.00	86.20	100.00	80 - 120
GS 50 to 4,999 kW (Co-Generation)	180.00	128.55	100.00	80 - 120
Large Use >5MW	80.00	129.42	110.00	85 - 115
Street Light	85.00	75.06	85.00	70 - 120
Sentinel	70.00	79.81	90.00	80 - 120
Unmetered Scattered Load	70.00	61.71	90.00	80 - 120
Standby	80.00	69.51	80.00	80 -120
		-	-	

Adjusted Appendix 2-P

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from 2009 Study	%	Costs Allocated in 2013 Test Year Study (Column 7A)	%
Residential	$ 31,448,713	57.57%	$ 38,826,252	56.13%
GS < 50 kW	$ 6,897,739	12.63%	$ 9,924,396	14.35%
GS > 50 kW < GS < 4,999 kW	$ 13,083,386	23.95%	$ 16,287,335	23.55%
GS 50 to 4,999 kW (Co-Generation)	$ 102,943	0.19%	$ 240,878	0.35%
Large Use >5MW	$ 1,148,208	2.10%	$ 1,403,971	2.03%
Street Light	$ 1,366,580	2.50%	$ 1,650,118	2.39%
Sentinel	$ 73,669	0.13%	$ 68,790	0.10%
Unmetered Scattered Load	$ 186,056	0.34%	$ 160,268	0.23%
Standby	$ 317,015	0.58%	$ 606,347	0.88%
Total	$ 54,624,309	100.00%	$ 69,168,355	100.00%

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C L.F. X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 36,097,050	$ 39,998,580	$ 36,986,398	$ 2,091,150
GS < 50 kW	$ 7,785,060	$ 8,626,504	$ 9,454,348	$ 470,048
GS > 50 kW < GS < 4,999 kW	$ 12,045,905	$ 13,347,881	$ 15,595,545	$ 691,791
GS 50 to 4,999 kW (Co-Generation)	$ 274,161	$ 303,794	$ 235,036	$ 5,842
Large Use >5MW	$ 1,606,434	$ 1,780,064	$ 1,507,429	$ 36,940
Street Light	$ 1,049,340	$ 1,162,758	$ 1,326,806	$ 75,794
Sentinel	$ 46,684	$ 51,730	$ 58,742	$ 3,168
Unmetered Scattered Load	$ 84,251	$ 93,357	$ 136,782	$ 7,459
Standby	$ 366,133	$ 405,706	$ 469,288	$ 15,790
Total	$ 59,355,018	$ 65,770,372	$ 65,770,372	$ 3,397,982

1 + d	1.1081

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2010	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	108.10	108.41	100.65	85 - 115
GS < 50 kW	108.80	91.66	100.00	80 - 120
GS > 50 kW < GS < 4,999 kW	80.00	86.20	100.00	80 - 120
GS 50 to 4,999 kW (Co-Generation)	180.00	128.54	100.00	80 - 120
Large Use >5MW	80.00	129.42	110.00	85 - 115
Street Light	85.00	75.06	85.00	70 - 120
Sentinel	70.00	79.81	90.00	80 - 120
Unmetered Scattered Load	70.00	62.91	90.00	80 - 120
Standby	80.00	69.51	80.00	80 -120
		-	-	

In referencing the changes in the Appendix 2-P: Cost Allocation from the originally filed worksheet to that of the adjusted worksheet, the Costs Allocated in 2013 Test Year Study(Column 7A) for USL move from $163,374 to an amount of $160,268. In regards to Load Forecast X Proposed Rates (Column 7D) the USL figures move from $139,577 to an amount of $135,782.

The resulting Status Quo Ratios reflected in Table C: Rebalancing Revenue-to-Cost (R/C) Ratios of Appendix 2-P: Cost Allocation reflect USL moving from a ratio of 61.71% to that of 62.91%. The Status Quo Ratios for Residential class does not reflct any adjustment (108.41% ratio). In rebalancing the Revenue-to-Cost Ratios, and due to the small adjustment amount for the USL class, the Proposed Ratios do not reflect any changes from that refelcted in the Application.

b) London Hydro can confirm the the load profile of Bus Shelters is established by using the calculated hours of use, and that Traffic Signals are established by wattage times 24 hours per day.

   The description in London Hydro's Conditions of Service, 3.8.2 Traffic Lights and 3.8.3 Bus Shelters had been revised to reflect both London Hydro practices and OEB regulatory requirements. London Hydro thanks Board staff for identification to London Hydro as to this disconnect between the information contained in the narrative of the Conditions of Service and the Distribution Systems Code and regrets any inconveniences that this may have caused.

Original Cost of Service Statement:

3.8.2 Traffic Signals

The location of supply for traffic signal systems will vary and must be established for each application through consultation with London Hydro.

Feeds may be from either the overhead or underground electrical systems and in all cases a disconnect switch will need to be installed and approved by the Electrical Safety Authority. All cabling used for the purpose of traffic signal installations, must be installed in dedicated conduits separate from street lighting or any other secondary duct work.

The service voltage for traffic signal systems will be 120 volts, single phase, 2 wire. Prior to the energization of a new traffic signal service, London Hydro will require notification from the Electrical Safety Authority that the installation has been inspected and approved. The final power source connection will be made by London Hydro or by the City of London's traffic signal contractor upon approval by London Hydro.

All traffic signal services will be unmetered and energy consumption will be based on the connected wattage and the calculated hours of use using the approved methods and rates established by the OEB. A connection fee for new traffic signal (and intersection lighting) feeds will apply based on London Hydro's approved commercial connection charge for a 100 Amp U/G 120/240 volt service. London Hydro personnel must be involved in the disconnection and reconnection of existing traffic signal services fed from padmount transformers or vaults where there is no disconnect switch accessible to the City of London's traffic signal Contractor. A charge per trip will apply as described in Appendix A.
London Hydro Inc. Conditions of Service

3.8.3 Bus Shelters
The service location for bus shelters will vary and must be established for each application through consultation with London Hydro. The service voltage will be 120 volts, single phase, 2 wire and the method of supply could be from either overhead or underground circuits.

All underground feeds must be in separate conduit from the bus shelter to the power supply location. For feeds originating from London Hydro's overhead system, the underground conduit for the cable riser will generally extend from the bus shelter to the nearest power supply pole. However, the service location could vary and London Hydro must be consulted for each application. Prior to the energization of a new bus shelter service, London Hydro will require notification from the Electrical Safety Authority that the installation has been inspected and approved. The final power source connection will be made by London Hydro.

Bus service shelters will be unmetered and energy consumption will be based on the connected wattage, utilized 24 hours per day, using the methods and rates approved by the OEB. A connection fee for new bus shelter feeds will apply based on London Hydro's approved connection charge for a 100 Amp U/G 120/240 volt service.

Revised Cost of Service Statement:

3.8.2 Traffic Signals

The location of supply for traffic signal systems will vary and must be established for each application through consultation with London Hydro.
Feeds may be from either the overhead or underground electrical systems and in all cases a disconnect switch will need to be installed and approved by the Electrical Safety Authority. All cabling used for the purpose of traffic signal installations, must be installed in dedicated conduits separate from street lighting or any other secondary duct work.

The service voltage for traffic signal systems will be 120 volts, single phase, 2 wire. Prior to the energization of a new traffic signal service, London Hydro will require notification from the Electrical Safety Authority that the installation has been inspected and approved. The final power source connection will be made by London Hydro or by the City of London's traffic signal contractor upon approval by London Hydro.

All traffic signal services will be unmetered and energy consumption will be based on the connected wattage, utilized 24 hours per day, using the methods and rates approved by the OEB. A connection fee for new traffic signal (and intersection lighting) feeds will apply based on London Hydro's approved commercial connection charge for a 100 Amp U/G 120/240 volt service. London Hydro personnel must be involved in the

disconnection and reconnection of existing traffic signal services fed from padmount transformers or vaults where there is no disconnect switch accessible to the City of London's traffic signal Contractor. A charge per trip will apply as described in Appendix A.
London Hydro Inc. Conditions of Service

3.8.3 Bus Shelters

The service location for bus shelters will vary and must be established for each application through consultation with London Hydro. The service voltage will be 120 volts, single phase, 2 wire and the method of supply could be from either overhead or underground circuits.

All underground feeds must be in separate conduit from the bus shelter to the power supply location. For feeds originating from London Hydro's overhead system, the underground conduit for the cable riser will generally extend from the bus shelter to the nearest power supply pole. However, the service location could vary and London Hydro must be consulted for each application. Prior to the energization of a new bus shelter service, London Hydro will require notification from the Electrical Safety Authority that the installation has been inspected and approved. The final power source connection will be made by London Hydro.

Bus service shelters will be unmetered and energy consumption will be based on the connected wattage and the calculated hours of use using the approved methods and rates established by the OEB. A connection fee for new bus shelter feeds will apply based on London Hydro's approved connection charge for a 100 Amp U/G 120/240 volt service.

c) i. The USL class includes the following types of notable unmetered loads:

.

- Rogers Cable Power Supplies – Load profile based on device rating and estimated hours of use.
- Traffic Signals and Crosswalks – Load profile based on device rating multiplied by 24 hours per day.
- Bus Shelters – Load profile based on device rating and estimated hours of use.
- Billboard Signs – Load profile based on device rating and estimated hours of use.
- Miscellaneous private lighting installations that have been grandfathered (previously referred to as dusk to dawn lighting) – Load profile based on device rating and estimated hours of use.

ii. The above loads do not have any temperature-sensitive or seasonal components built into these rates.

Rate Design (Exhibit 8)

Retail Transmission Service Rates Presentation Differences

Question OEB 41

References: Exh 8, Appendix 8A; Exh 9, Appendix 9E

The forecasts of Wholesale Transmission Costs differ between the two sources referenced above. The costs that are used to calculate the proposed Retail Transmission Service Rates in Exhibit 8 are lower than those that are used to calculate the Cost of Power in Exhibit 9 (which is used for the Working Capital Allowance).

a) *Please explain the difference between the costs in the two exhibits referenced above.*

b) *Please confirm that London Hydro will update both of these calculations upon Board approval of Uniform Transmission Rates for 2013, together with corresponding retail rates.*

Response OEB 41

a) The cost differences of Wholesale Transmission Costs between Appendix 8A and Appendix 9E are mainly from load data approaches required to be taken in order to populate each of these Appendices.

The load data used to calculate Appendix 8A (better identified as OEB RTSR Workform for Electricity Distributors -2013 Filers) uses the most recent reported RRR billing determinates for non-loss adjusted metered kWh and kW. This data is populated in Tab 4: RRR Data. In the case for London Hydro, our last RRR data to be filed was for 2011. Therefore, actual 2011 (reported RRR data) was used in the RTSR Workform model.

The same data recorded on Tab 4: RRR Data populates the rest of the RTSR Workform model. In regards to determining the costs (Network and Connection)

the model has calculated the proposed adjusted RTSR Network and the RTSR Connection rates for 2013, and multiplies these proposed rates using the same RRR billed data 2011 data contained in Tab 4: RRR Data. By comparing the billing data in Tab 4: RRR Data with that of Tab 11: Adjusted Network to Forecasted WS and Tab 12: Adjusted Connection to Forecasted WS the loss adjusted billed kWh/ kW data matches.

It should be pointed out that the loss adjusted billed kWh/ kW data for both Tab11: Adjusted Network to Forecasted WS and Tab 12: Adjusted Connection to Forecasted WS the loss adjusted billed kWh/ kW is hard coded. The data reflected Tab 4: RRR Data can only be used for the rest of the worksheet.

The proposed 2013 RTSR Network and the Connection rates for both Tab11: Adjusted Network to Forecasted WS and Tab 12: Adjusted Connection to Forecasted WS agreed to the proposed 2013 rates as reflected in Appendix 9E: Cost of Power Calculation 2013 Test Year.

As reflected in the Table: Appendix 9E Cost of Power Calculation 2013 Test Year although the same proposed rates are used as identified in Appendix 8A although the Loss adjusted billed kWh / kW are different. The Loss adjusted billed kWh / kW quantities are proposed forecasted load (as per Exhibit 3. Table 3-25 – Summary of Forecast, pg. 28). These same load forecast numbers in the Application could not be imputed in the hard coded Appendix 8A (OEB RTSR Workform for Electricity Distributors -2013 Filers).

If the intent of Appendix 8A (OEB RTSR Workform) is to have the Application proposed load forecasted numbers included in the RTSR Workform, London Hydro would proceed to provide for this adjustment, however London Hydro would have to request for modifications to the OEB RTSR Workform for Electricity Distributors -2013 Filers to be able to appease having both Appendix 8A and Appendix 9E to arrive at same Network and Connection costs.

Table: RTSR Workform Tab 4: RRR Data

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	1,128,889,459				1,128,889,459	-
General Service Less Than 50 kW	kWh	407,986,442				407,986,442	-
General Service 50 to 4,999 kW	kW	405,214,652	1,139,954		48.72%	405,214,652	1,139,954
General Service 50 to 4,999 kW – Interval Metered	kW	1,113,331,947	2,678,768		56.96%	1,113,331,947	2,678,768
General Service 1,000 To 4,999 kW (co-generation)	kW	37,918,668	48,044		108.18%	37,918,668	48,044
Standby Power - APPROVED ON AN INTERIM BASIS	kW		154,800		0.00%	-	154,800
Large Use	kW	193,549,148	409,088		64.85%	193,549,148	409,088
Street Lighting	kW	23,650,724	66,345		48.86%	23,650,724	66,345
Sentinel Lighting	kW	812,670	2,203		50.56%	812,670	2,203
Unmetered Scattered Load	kWh	5,645,414				5,645,414	-

Table: RTSR Workform Tab 11: Adjusted Network to Forecasted WS

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0071	1,128,889,459	-	$ 7,976,579	35.0%	$ 7,976,579	$ 0.0071
General Service Less Than 50 kW	kWh	$ 0.0066	407,986,442	-	$ 2,676,864	11.7%	$ 2,676,864	$ 0.0066
General Service 50 to 4,999 kW	kW	$ 2.3133	405,214,652	1,139,954	$ 2,637,012	11.6%	$ 2,637,012	$ 2.3133
General Service 50 to 4,999 kW – nterval Metered	kW	$ 2.9665	1,113,331,947	2,678,768	$ 7,946,436	34.8%	$ 7,946,436	$ 2.9665
General Service 1,000 To 4,999 kW co-generation)	kW	$ 3.4245	37,918,668	48,044	$ 164,528	0.7%	$ 164,528	$ 3.4245
Standby Power - APPROVED ON AN INTERIM BASIS	kW	$ -	-	154,800	$ -	0.0%	$ -	$ -
.arge Use	kW	$ 3.0387	193,549,148	409,088	$ 1,243,106	5.4%	$ 1,243,106	$ 3.0387
Street Lighting	kW	$ 2.0369	23,650,724	66,345	$ 135,137	0.6%	$ 135,137	$ 2.0369
Sentinel Lighting	kW	$ 2.0396	812,670	2,203	$ 4,493	0.0%	$ 4,493	$ 2.0396
Jnmetered Scattered Load	kWh	$ 0.0066	5,645,414	-	$ 37,040	0.2%	$ 37,040	$ 0.0066
					$ 22,821,196			

Table: RTSR Workform Tab 12: Adjusted Connection to Forecasted WS

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0055	1,128,889,459	-	$ 6,188,288	34.3%	$ 6,188,288	$ 0.0055
General Service Less Than 50 kW	kWh	$ 0.0048	407,986,442	-	$ 1,941,095	10.8%	$ 1,941,095	$ 0.0048
General Service 50 to 4,999 kW	kW	$ 1.7761	405,214,652	1,139,954	$ 2,024,656	11.2%	$ 2,024,656	$ 1.7761
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.4750	1,113,331,947	2,678,768	$ 6,629,838	36.7%	$ 6,629,838	$ 2.4750
General Service 1,000 To 4,999 kW (co-generation)	kW	$ 2.6180	37,918,668	48,044	$ 125,779	0.7%	$ 125,779	$ 2.6180
Standby Power - APPROVED ON AN INTERIM BASIS	kW	$ -	-	154,800	$ -	0.0%	$ -	$ -
Large Use	kW	$ 2.4750	193,549,148	409,088	$ 1,012,476	5.6%	$ 1,012,476	$ 2.4750
Street Lighting	kW	$ 1.5640	23,650,724	66,345	$ 103,760	0.6%	$ 103,760	$ 1.5640
Sentinel Lighting	kW	$ 1.5659	812,670	2,203	$ 3,450	0.0%	$ 3,450	$ 1.5659
Unmetered Scattered Load	kWh	$ 0.0048	5,645,414	-	$ 26,859	0.1%	$ 26,859	$ 0.0048
					$ 18,056,202			

Table: Appendix 9E Cost of Power Calculation 2013 Test Year

Transmission - Network Class per Load Forecast		Volume Metric		2013	
Residential		kWh	1,119,299,865	$0.0071	$7,947,029
General Service < 50 kW		kWh	406,661,557	$0.0066	$2,683,966
General Service 50 to 4,999 kW Non-Interval	31%	kW	1,227,821	$2.3133	$2,840,318
General Service 50 to 4,999 Kw Interval	69%	kW	2,686,754	$2.9665	$7,970,255
GS 50 to 4,999 kW (Co-Generation)		kW	203,466	$3.4245	$696,769
Large Use >5MW		kW	387,522	$3.0387	$1,177,563
Street Lighting		kW	67,255	$2.0369	$136,992
Sentinel Lighting		kW	2,130	$2.0396	$4,344
Unmetered Scattered Load		kWh	5,169,637	$0.0066	$34,120
TOTAL					**$23,491,357**

Transmission - Connection Class per Load Forecast		Volume Metric		2013	
Residential		kWh	1,119,299,865	$0.0055	$6,156,149
General Service < 50 kW		kWh	406,661,557	$0.0048	$1,951,975
General Service 50 to 4,999 kW Non-Interval	31%	kW	1,217,025	$1.7761	$2,161,557
General Service 50 to 4,999 Kw Interval	69%	kW	2,697,550	$2.4750	$6,676,436
GS 50 to 4,999 kW (Co-Generation)		kW	203,466	$2.6180	$532,674
Large Use >5MW		kW	387,522	$2.4750	$959,117
Street Lighting		kW	67,255	$1.5640	$105,187
Sentinel Lighting		kW	2,130	$1.5659	$3,335
Unmetered Scattered Load		kWh	5,169,637	$0.0048	$24,814
TOTAL					**$18,571,246**

b) London Hydro confirms that it will update calculations upon Board approval of the Uniform Transmission Rates for 2013, together with corresponding retail rates (that include the Retail Transmission Service Rates).

With respect to this matter, London Hydro acknowledges the receipt of the Board's Rate Order, 2013 Uniform Electricity Transmission Rates, dated December 20, 2012 (EB-2012-0031). As reference in the above Decision the new Uniform Electricity Transmission Rates are:

RATE SCHEDULE: PTS	PROVINCIAL TRANSMISSION SERVICE

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand[1,2]	**3.63**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.75**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**1.85**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

London Hydro would respectfully ask that the Board staff accept the refilling of the OEB Excel model RTRS Workform for Electricity Distributors (2013 Filers) that includes the new approved Uniform Transmission Rates. Significant tabs of the updated London Hydro RTRS Workform are as follows.

Uniform Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.63
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.75
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.85

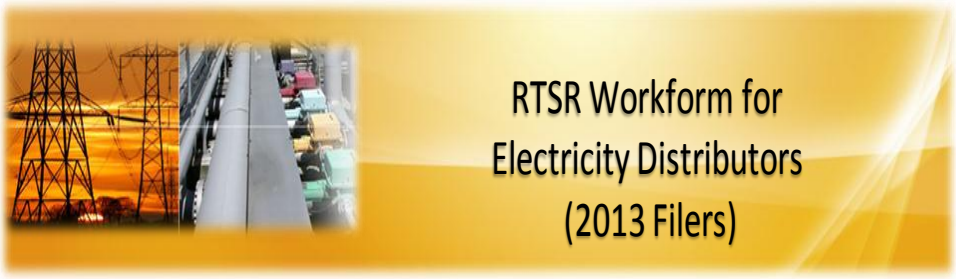
Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0071	1,128,889,459	-	$ 7,976,579	35.0%	$ 8,110,639	$ 0.0072
General Service Less Than 50 kW	kWh	$ 0.0066	407,986,442	-	$ 2,676,864	11.7%	$ 2,721,853	$ 0.0067
General Service 50 to 4,999 kW	kW	$ 2.3133	405,214,652	1,139,954	$ 2,637,012	11.6%	$ 2,681,332	$ 2.3521
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.9665	1,113,331,947	2,678,768	$ 7,946,436	34.8%	$ 8,079,990	$ 3.0163
General Service 1,000 To 4,999 kW (co-generation)	kW	$ 3.4245	37,918,668	48,044	$ 164,528	0.7%	$ 167,293	$ 3.4821
Standby Power - APPROVED ON AN INTERIM BASIS	kW	$ -	-	154,800	$ -	0.0%	$ -	$ -
Large Use	kW	$ 3.0387	193,549,148	409,088	$ 1,243,106	5.4%	$ 1,263,999	$ 3.0898
Street Lighting	kW	$ 2.0369	23,650,724	66,345	$ 135,137	0.6%	$ 137,408	$ 2.0711
Sentinel Lighting	kW	$ 2.0396	812,670	2,203	$ 4,493	0.0%	$ 4,569	$ 2.0739
Unmetered Scattered Load	kWh	$ 0.0066	5,645,414	-	$ 37,040	0.2%	$ 37,663	$ 0.0067
					$ 22,821,196			

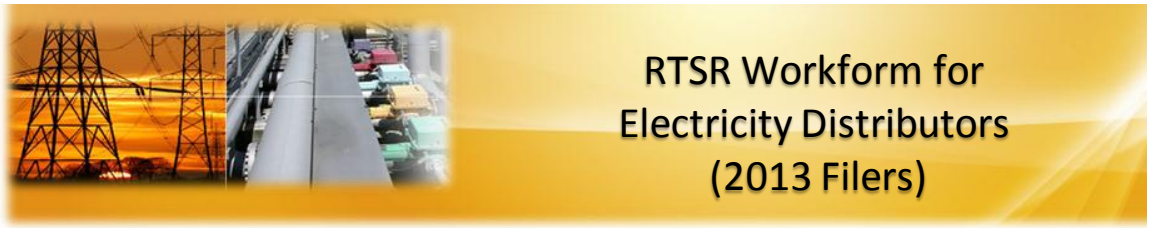
The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0070	1,128,889,459	-	$ 7,902,226	35.0%	$ 7,976,579	$ 0.0071
General Service Less Than 50 kW	kWh	$ 0.0065	407,986,442	-	$ 2,651,912	11.7%	$ 2,676,864	$ 0.0066
General Service 50 to 4,999 kW	kW	$ 2.2917	405,214,652	1,139,954	$ 2,612,432	11.6%	$ 2,637,012	$ 2.3133
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.9388	1,113,331,947	2,678,768	$ 7,872,364	34.8%	$ 7,946,436	$ 2.9665
General Service 1,000 To 4,999 kW (co-generation)	kW	$ 3.3926	37,918,668	48,044	$ 162,994	0.7%	$ 164,528	$ 3.4245
Standby Power - APPROVED ON AN INTERIM BASIS	kW	$ -	-	154,800	$ -	0.0%	$ -	$ -
Large Use	kW	$ 3.0104	193,549,148	409,088	$ 1,231,519	5.4%	$ 1,243,106	$ 3.0387
Street Lighting	kW	$ 2.0179	23,650,724	66,345	$ 133,878	0.6%	$ 135,137	$ 2.0369
Sentinel Lighting	kW	$ 2.0206	812,670	2,203	$ 4,451	0.0%	$ 4,493	$ 2.0396
Unmetered Scattered Load	kWh	$ 0.0065	5,645,414	-	$ 36,695	0.2%	$ 37,040	$ 0.0066
					$ 22,608,471			



The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0055	1,128,889,459	-	$ 6,188,288	34.3%	$ 6,048,726	$ 0.0054
General Service Less Than 50 kW	kWh	$ 0.0048	407,986,442	-	$ 1,941,095	10.8%	$ 1,897,318	$ 0.0047
General Service 50 to 4,999 kW	kW	$ 1.7761	405,214,652	1,139,954	$ 2,024,656	11.2%	$ 1,978,995	$ 1.7360
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.4750	1,113,331,947	2,678,768	$ 6,629,838	36.7%	$ 6,480,318	$ 2.4191
General Service 1,000 To 4,999 kW (co-generation)	kW	$ 2.6180	37,918,668	48,044	$ 125,779	0.7%	$ 122,943	$ 2.5590
Standby Power - APPROVED ON AN INTERIM BASIS	kW	$ -	-	154,800	$ -	0.0%	$ -	$ -
Large Use	kW	$ 2.4750	193,549,148	409,088	$ 1,012,476	5.6%	$ 989,642	$ 2.4191
Street Lighting	kW	$ 1.5640	23,650,724	66,345	$ 103,760	0.6%	$ 101,420	$ 1.5287
Sentinel Lighting	kW	$ 1.5659	812,670	2,203	$ 3,450	0.0%	$ 3,372	$ 1.5306
Unmetered Scattered Load	kWh	$ 0.0048	5,645,414	-	$ 26,859	0.1%	$ 26,254	$ 0.0047
					$ 18,056,202			



For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0072	$ 0.0054
General Service Less Than 50 kW	kWh	$ 0.0067	$ 0.0047
General Service 50 to 4,999 kW	kW	$ 2.3521	$ 1.7360
General Service 50 to 4,999 kW – Interval Metered	kW	$ 3.0163	$ 2.4191
General Service 1,000 To 4,999 kW (co-generation)	kW	$ 3.4821	$ 2.5590
Standby Power - APPROVED ON AN INTERIM BASIS	kW	$ -	$ -
Large Use	kW	$ 3.0898	$ 2.4191
Street Lighting	kW	$ 2.0711	$ 1.5287
Sentinel Lighting	kW	$ 2.0739	$ 1.5306
Unmetered Scattered Load	kWh	$ 0.0067	$ 0.0047

Deferral and Variance Accounts (Exhibit 9)

Audit Results

Question OEB 42

Reference: EB-2012-0380 "Application for Disposition RSVA Group 1 Accounts" (pre-filed evidence filed September 25, 2012) p. 10.

a) *Has London Hydro's external auditor reviewed the adjustments made to Account 1588 in June 2012, namely the $3.8 million debit to Account 1588 sub-account GA and the $3.8 million credit to the control account of Account 1588.*
b) *If yes to part a), what were the results of the review? Please file with the Board any documentation that has been provided by the external auditors.*
c) *If yes to part a), how is the external auditor planning to account for the error in the London Hydro 2012 audited financial statements? Please explain.*
d) *If no to part a), why was no review undertaken? Please explain.*

Response OEB 42

a) No, our external auditors have not reviewed the adjustment requiring a $3.8 million dollar credit and debit to account 1588 although the adjustments have been discussed with the auditors.

b) Not applicable

c) Not applicable

d) The adjustment was discussed with our external auditor and cause and impact of the adjustment was communicated. As the adjustment is simply a classification difference of a liability it was determined that a review will be undertaken during the 2012 audit and the 2011 amounts will be reclassified with the appropriate note disclosure included within the financial statements.

Continuity Schedules

Question OEB 43

Reference: DVA Continuity Schedules; EB 2008-0235, p. 48

The Board "Finding" in the Board Decision EB 2008-0235 specified the DVAs to be disposed effective May 1, 2009.

Board staff noted that the amounts approved for disposition in EB 2008-0235, p. 48, do not match with the amounts in 2009 DVA Continuity Schedule under columns "Board-Approved Disposition During 2009" for principal and "Board-Approved Disposition During 2009" for interest.

a) *Please confirm if London Hydro reflected the disposition of the approved DVA balances in the DVA Continuity Schedule provided in this application.*

b) *If the answer to part a is "no", please update the "Board Approved Disposition During 2009" columns for both the principal and interest and reflect the revised DVA balances from 2009 onwards, re-file DVA Continuity Schedule including Account 1595 as per EB 2008-0235 and update all other related evidence.*

Response OEB 43

a) Yes, London Hydro confirms it reflected the disposition of the final approved DVA balances in the DVA Continuity Schedule. The last disposition of the RSVA balances were approved with the 2012 IRM application (EB-2012-0181), and therefore reflected under Board Approved Disposition for that year. The 2009 disposition balances were not separately reflected in the DVA Continuity Schedule under "Board Approved Disposition", instead they were summarized under the current year transactions.

Please refer to part b) for the revised DVA Continuity Schedule.

The DVA Continuity Schedules EB-2008-0235 p. 48 reflected the DVA balances with carrying charges up to April 30, 2009. The actual implementation date of the 2009 rates and rate riders is October 1, 2009 with effective date of May 1, 2009.

The Board directed London Hydro to include updated documentation in its Draft Rate Order which shows the account balances at December 31, 2008, the interest calculated from January 1 to September 30, 2009, the allocation of each account to each rate class, and the monthly amount to be refunded including confirmation of the length of the disposition period.

Please refer to **Table: Final Deferral and Variance Accounts** for final disposition amounts, which are also reflected in the DVA Continuity Schedule.

Board Findings London Hydro Inc. EB-2008-0235 Decision and Order, dated August 21, 2009. (Page 49)

Board Findings

While the Board has announced an initiative to consider on a generic basis certain of the deferral and variance accounts, that process is still in the early stages. The RSVA balances are large and the Board finds that these amounts should be disposed of at this time. A rebasing application is an appropriate time at which to consider disposition of each account. The Board finds it appropriate to dispose of all the accounts, except the two PILS accounts (which are subject to a review in a separate proceeding), account 1590 (which the Board has typically not disposed of until the final balance can be verified), and the smart meter and CDM tracking accounts (which will be reviewed at a later date).

The Board finds that the balances at December 31, 2008 shall be disposed of, plus projected interest to the effective date of the 2009 distribution rates.

The Board finds that a period from the implementation date through to April 30, 2011 is appropriate.

The Board directs London to include updated documentation in its Draft Rate Order which shows the account balances at December 31, 2008, the interest calculated from January 1 to September 30, 2009, the allocation of each account to each rate class, and the monthly amount to be refunded including confirmation of the length of the disposition period.

Table: Final Deferral and Variance Accounts

Deferral and Variance Accounts	Account	Principal Balance Dec 31/08	Interest to Dec 31/08	Total Balance Dec 31/08	2009 Interest Jan 1 to Mar 31 2.45%	2009 Interest Apr 1 to June 30 1.0%	2009 Interest July 1 to Sept 30 .55%	Forecast Balance Sept 30/09
RSVA - Wholesale Market Service Charges	1580	$ (8,012,410)	$ (351,865)	$ (8,364,275)	$ (48,404)	$ (19,976)	$ (11,108)	$ (8,443,762)
RSVA - One-time Wholesale Market Service	1582	$ 302,950	$ 53,791	$ 356,741	$ 1,830	$ 755	$ 420	$ 359,746
RSVA - Retail Transmission Network Charges	1584	$ 299,995	$ 202,411	$ 502,406	$ 1,812	$ 748	$ 416	$ 505,382
RSVA - Retail Transmission Connection Charges	1586	$ (1,042,852)	$ (59,601)	$ (1,102,453)	$ (6,300)	$ (2,600)	$ (1,446)	$ (1,112,799)
RSVA - Power - excluding Global Adjustment sub account	1588	$ (2,491,900)	$ (523,489)	$ (3,015,389)	$ (15,054)	$ (6,213)	$ (3,455)	$ (3,040,110)
RSVA - Power - Global Adjustment sub account	1588	$ 2,002,932	$ (20,903)	$ 1,982,029	$ 12,100	$ 4,994	$ 2,777	$ 2,001,899
Other Regulatory Assets - Sub-account OEB Cost Assessments	1508	$ 392,670	$ 66,230	$ 458,900	$ 2,372	$ 979	$ 544	$ 462,795
Other Regulatory Assets - Sub-account Pension Contributions	1508	$ 1,491,745	$ 208,537	$ 1,700,282	$ 9,012	$ 3,719	$ 2,068	$ 1,715,081
Retail Cost Variance Account - Retail	1518	$ (173,238)	$ (11,254)	$ (184,492)	$ (1,047)	$ (432)	$ (240)	$ (186,211)
Retail Cost Variance Account - STR	1548	$ 113,999	$ 15,632	$ 129,631	$ 689	$ 284	$ 158	$ 130,762
Miscellaneous Deferred Debits - Payments to Customers	1525	$ 30,810	$ -	$ 30,810	$ -	$ -	$ -	$ 30,810
Low Voltage Variance Account	1550	$ 10,253	$ 520	$ 10,773	$ 62	$ 26	$ 14	$ 10,875
		$ (7,075,046)	**$ (419,992)**	**$ (7,495,038)**	**$ (42,927)**	**$ (17,716)**	**$ (9,851)**	**$ (7,565,532)**

EB-2008-0235 p. 48 reflects DVA balances including forecasted transactions and projected interest to April 30, 2009.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	London Hydro Inc
Application ID NUMBER	EB-200X-XXXX
Date	

	Board Rate	Days	Average Interest 08 Annual
Q1 - 08	0.0514	91	0.0128
Q2 - 08	0.0418	91	0.0104
Q3 - 08	0.0335	92	0.0084
Q4 - 08	0.0335	92	0.0084
Weighted Average Rate			3.99%

	Board Rate	Days	Average Interest 09 Annual
Q1 - 09	0.0245	90	0.0184
Apr r09	0.01	30	0.0025
		120	
			2.09%

Account Description	Account Number	Projected Interest on Dec 31 -07 balance from Jan 1, 2008 to Dec 31, 2008 [7]	Projected Interest on Dec 31 -07 balance from Jan 1, 2009 to April 30, 2009 [7]	Balance before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to Dec 31, 2008	Forecasted Transactions, Excluding Interest from Jan 1, 2009 to April 30, 2009	Projected Interest from Jan 1, 2008 to Dec 31, 2008 on Forecasted Transx for 2008	Projected Interest from Jan 1, 2009 to April 30, 2009 on Forecasted Transx for 2008 and 2009	Balance
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 15,668	$ 2,695	$ 461,647	$ -				$ 461,647
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 59,521	$ 10,238	$ 1,710,720	$ -	$ -	$ -	$ -	$ 1,710,720
Other Regulatory Assets - Sub-Account - Bill 210 Cheque Issuance Costs	1508	$ -	$ -	$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508	$ -	$ -	$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508	$ -	$ -	$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ (5,586)	$ (961)	$ (151,636)	$ (33,236)	$ (12,600)	$ (694)	$ (86)	$ (198,252)
Misc. Deferred Debits	1525	$ -	$ -	$ 30,810	$ -	$ -	$ -	$ -	$ 30,810
Retail Cost Variance Account - STR	1548	$ 3,590	$ 617	$ 105,853	$ 24,034	$ 9,844	$ 502	$ 68	$ 140,300
Qualifying Transition Costs [4]	1570	$ -	$ -	$ -	$ -				$ -
Pre-Market Opening Energy Variances Total [4]	1571	$ -	$ -	$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -	$ -	$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -				$ -
RSVA – One-time Wholesale Market Service	1582	$ -	$ -	$ -	$ -				$ -
Other Deferred Credits	2425	$ -	$ -	$ -	$ -				$ -
Sub-Total		$ 73,192	$ 12,589	$ 2,157,395	$ (9,202)	$ (2,756)	$ (192)	$ (19)	$ 2,145,226
Smart Meter Capital and Recovery Offset	1555	$ (17,240)	$ (2,965)	$ (457,812)	$ (484,796)	$ (167,086)	$ (8,100)	$ (4,218)	$ (1,122,012)
Smart Meter Operaqtion, Maintenance and Administration	1556	$ 1,503	$ 258	$ 40,514	$ 106,552	$ 235,886	$ 1,051	$ 1,566	$ 385,569
Deferred Payments in Lieu of Taxes	1562	$ 4,988	$ 858	$ 673,052	$ -	$ -	$ -	$ -	$ 673,052
Deferred PILs Contra Account [8]	1563	$ -	$ -	$ -					$ -
CDM Expenditrues and Recoveries	1565	$ (0)	$ (0)	$ (0)	$ -	$ -	$ -	$ -	$ (0)
CDM Contra Account	1566	$ -	$ -	$ -					$ -
Recovery of Regulatory Asset Balances	1590	$ 14,782	$ -	$ 3,283,469	(2,598,880)	$ -	$ -	$ -	$ 684,589
2006 PILs & Taxes Variance	1592	$ (5,192)	$ (893)	$ (143,127)	-	$ -	$ -	$ -	$ (143,127)
No sub-total									
Low Voltage Variance Account	1550	$ 240	$ 41	$ 6,525	$ 4,227	$ 341	$ 97	$ 2	$ 11,192
RSVA - Wholesale Market Service Charge	1580	$ (243,760)	$ (41,928)	$ (6,462,160)	$ (1,850,000)	$ 80,000	$ (44,835)	$ (14,257)	$ (8,291,252)
RSVA - One Time Charges	1582	$ 12,088	$ 2,079	$ 358,861	$ -	$ -	$ (2,481)	$ -	$ 356,380
RSVA - Retail Transmission Network Charge	1584	$ 76,117	$ 13,093	$ 2,165,403	$ (1,666,545)	$ (280,000)	$ 1,275	$ (15,679)	$ 204,454
RSVA - Retail Transmission Connection Charge	1586	$ (1,122)	$ (193)	$ (63,102)	$ (1,032,424)	$ (200,000)	$ (6,894)	$ (9,927)	$ (1,312,347)
RSVA - Power (including Global Adjustment)	1588	$ (52,188)	$ (8,977)	$ (1,763,765)	$ 818,995	$ 300,000	$ (87,031)	$ 9,013	$ (722,788)
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 35,360	$ 6,082	$ 867,714	$ 1,074,898	$ -	$ 38,361	$ 8,658	$ 1,989,631
Sub-Total		$ (208,624)	$ (35,884)	$ (5,758,239)	$ (3,725,747)	$ (99,659)	$ (139,869)	$ (30,848)	$ (9,754,361)
Footnotes									

EB-2008-0235
London Hydro Inc.
Appendix OEB 110 (36b) - Deferral Accounts (revised)
Filed: May 26, 2009
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b) Response:

Revised Schedule for Year 2009 (including the RSVA power account and GA)

Account Descriptions	Account Number	2009									
		Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -	-$ 8,651,588	-$ 8,012,410		-$ 639,178	$ -	-$ 433,975	-$ 431,352		-$ 2,623
RSVA - Retail Transmission Network Charge	1584	$ -	$ 639,090	$ 299,995		$ 339,095	$ -	$ 205,492	$ 205,386		$ 106
RSVA - Retail Transmission Connection Charge	1586	$ -	-$ 1,482,860	-$ 1,042,852		-$ 440,008	$ -	-$ 71,805	-$ 69,947		-$ 1,858
RSVA - Power (excluding Global Adjustment)	1588	$ -	-$ 4,131,073	-$ 2,491,900		-$ 1,639,173	$ -	-$ 590,225	-$ 548,210		-$ 42,015
RSVA - Power - Sub-account - Global Adjustment	1588	$ -	$ 3,148,937	$ 2,002,932		$ 1,146,005	$ -	-$ 12,538	-$ 1,033		-$ 11,505
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008) [7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009) [7]	1595	$ -	-$ 6,449,923			-$ 6,449,923	$ -	-$ 500,135			-$ 500,135
Disposition and Recovery/Refund of Regulatory Balances (2010) [7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	-$ 16,927,417	-$ 9,244,235	$ -	-$ 7,683,182	$ -	-$ 1,403,186	-$ 845,156	$ -	-$ 558,030
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	-$ 20,076,354	-$ 11,247,167	$ -	-$ 8,829,187	$ -	-$ 1,390,648	-$ 844,123	$ -	-$ 546,525
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ 3,148,937	$ 2,002,932	$ -	$ 1,146,005	$ -	-$ 12,538	-$ 1,033	$ -	-$ 11,505
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	$ 135,327			$ 135,327	$ -	$ 72			$ 72
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act [8]	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 173,238	-$ 39,087	-$ 173,238		-$ 39,087	-$ 11,254	-$ 1,847	-$ 12,973		-$ 128
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ 113,999	$ 30,243	$ 113,999		$ 30,243	$ 15,632	$ 1,230	$ 16,763		$ 99
Board-Approved CDM Variance Account	1567										$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		-$ 59,239	$ 126,483	-$ 59,239	$ -	$ 126,483	$ 4,378	-$ 545	$ 3,790	$ -	$ 43
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 130,133				-$ 130,133	-$ 12,084	-$ 1,471			-$ 13,555
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 189,372	-$ 16,800,934	-$ 9,303,474	$ -	-$ 7,686,832	-$ 7,706	-$ 1,405,202	-$ 841,366	$ -	-$ 571,542
Special Purpose Charge Assessment Variance Account [9]	**1521**										

Balances for Disposition

Question OEB 44

References:

i. Exh 9, DVA Continuity Schedule Work Form

ii. *Filing Requirements for Electricity Transmission & Distribution Applications, Chapter 2, S.2.12, p.51.*

The 2013 Cost of Service filing requirements states:

> *"Interest rates applied to calculate the carrying charges for each regulatory deferral and variance account. The applicant must provide the rates by month or by quarter for each year. "*

Please provide the interest rates used for each DVA account by month or by quarter for each year as per 2013 COS filing requirements.

Response OEB 44

The interest on DVA balances is calculated using the Board's prescribed rate for each quarter.

The quarterly Board Approved Prescribed Interest Rates for Deferral and Variance Accounts used in calculation of carrying charges:

Quarter	Interest Rate
2009 QTR 1	2.45%
2009 QTR 2	1.00%
2009 QTR 3	0.55%
2009 QTR 4	0.55%
2010 QTR 1	0.55%
2010 QTR 2	0.55%
2010 QTR 3	0.89%
2010 QTR 4	1.20%
2011 QTR 1	1.47%
2011 QTR 2	1.47%
2011 QTR 3	1.47%
2011 QTR 4	1.47%
2012 QTR 1	1.47%
2012 QTR 2	1.47%
2012 QTR 3	1.47%
2012 QTR 4	1.47%
2013 QTR 1	1.47%
2013 QTR 2	1.47%

The forecasted interest on December 31, 2011 principal balances of the DVA accounts is calculated using the current Board's prescribed rate of 1.47% for the period of January 1, 2012 to April 30, 2013.

References: page 9-1 Line 10-12, and page 15 Table 9-3 – Deferral and Variance Accounts Submitted for Recovery with this Application.

Balances for Disposition

Question OEB 45

References: Exh 9, pp. 4 and 15, Table 9-3, 'DVAs Submitted for Recovery with this Application'; Appendix 2-U

Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs is being used by London Hydro to record incremental one-time costs associated with the transition to IFRS during the period March 2009 to December 2011.

In addition, London Hydro is requesting disposition of Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs account balance of $362,490 in

Table 9-3. London Hydro stated that this account will continue until such time as transition to IFRS is complete for January 1, 2013, Since IFRS is not fully implemented, additional costs will be incurred.

a) *Please confirm that the $362,490 costs are incremental costs and not included in the 2013 OM&A expenses for the test year.*

b) *Please state the percentage of completion of the IFRS Transition Costs relating to the $362,490.*

c) *As London Hydro expects that the DVA 1508 sub account above will continue when the transition to IFRS is complete, please identify the projected additional IFRS related activities and incremental costs to completion using the format in Appendix 2-U.*

Response OEB 45:

a) London Hydro confirms that the $362,490 costs are incremental costs and not included in the 2013 OM&A expenses for the test year.

The amount of $362,490 is the amount being requested for disposition of Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs account.

The amount $362,490 (Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs) as reflected in Table 9-3: Deferral and Variance Accounts Submitted for Recovery with this Application in Exhibit 9, page 15, composes of deferred costs from 2009 through to 2011 for IFRS Transition Costs. The annual amounts that compose this account balance are reflected below:

Year		Principle	Carrying Charges	
2009	*	$ 135,327		
2010	*	$ 139,434		
2011	*	$ 74,263	$ 6,650	*
		$ 349,024	$ 6,650	
January 1, 2012 to April 30, 2013			$ 6,817	
Total for Recovery			$ 362,490	
* Audited Figures				

b) London Hydro estimates that the IFRS Transition Costs totalling to the $362,490 would be 80 percent of the anticipated costs.

c) As Reflected in a copy of Appendix 2-U: One Time Incremental IFRS Transition Costs the total that London Hydro is seeking for recovery in this Application of Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs is $ 362,490 (of which $355,673.38 applied to costs and carrying charges up to December 31, 2011, and these figures have been audited) **.** The total amount being applied for includes incremental costs not included in OM&A, and carrying charges up to April 30, 2013. Amounts approved as per Board Decision EB-2008-2035 (London Hydro Cost of Service rate application) amount of $25,000 per year for 2009, 2010, and 2011 have been deducted from the Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs.

Further reflected in the Appendix 2-U is actual incremental costs incurred in 2012 in the total amount of $37,940 and applied to Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs. Offsetting this amount is the $25,000 as approved per Board Decision EB-2008-2035 (London Hydro Cost

of Service rate application). Carrying charges of $5,217 were also recorded for 2012. These figures have not been audited, although are expected to be audited before the conclusion of this Application proceedings.

Projected Test Year 2013 incremental costs associated with Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs total $65,000 ($50,000 for professional accounting services and $15,000 for required IFRS pension actuarial review). These costs have not been included in 2013 OM&A costs.

Total amount projected to be included in Account 1508, Other Regulatory Assets-Sub Account Deferred IFRS Transition Costs as at December 31, 2013 is $444,048, with carrying charges only calculated to December 31, 2012, as identified in Appendix 2-U.

						JN - July 27, 2012		on Dec 19, 2012		
Appendix 2-U One Time Incremental IFRS Transition Costs details - for 2013 COS										
			Annual 2009	**Annual 2010**	**Annual 2011**	**YTD at Dec 2011**	**Annual 2012 Bridge Year**	**YTD at Dec 2012**	**Annual 2013 Test Year**	**YTD at Dec 2013**
			Actual/ Audited	Actual/ Audited	Actual/ Audited	Actual/ Audited	Actual		Projected	Projected
Non-Incremental expenses - recovered through current rates										
	Amount approved as per decision and order, effective September 1, 2009 - EB-2008-0235		(25,000.00)	(25,000.00)	(25,000.00)	(75,000.00)	(25,000.00)	(100,000.00)		(100,000.00)
Incremental Consulting										
KPMG	- professional accounting fees:									
	Study re conversion from Canadian GAAP to IFRS*		74,372.50	24,637.50	8,052.50	107,062.50	33,090.00	140,152.50	50,000.00	190,152.50
Syntax Systems	- system upgrades, changes where IFRS was the major reason for changes:									
	JDE Consultation IFRS assessment workshop, report	Contract # 16192	39,294.08	(23,522.83)	-	15,771.25		15,771.25		15,771.25
	JDE Consultation IFRS EnterpriseOne Project	Contract # 16221		46,449.80	555.00	47,004.80		47,004.80		47,004.80
	JDE Development - Programming	Contract # 16313		10,246.50	-	10,246.50		10,246.50		10,246.50
	EnterpriseOne Platform Migration - Sun/Oracle to WIN/RedHat/Oracle (multi ledger)	Contract # 16335		17,208.00	(1,500.00)	15,708.00		15,708.00		15,708.00
	Travel and related expenses			15,278.48	444.66	15,723.14		15,723.14		15,723.14
			39,294.08	65,659.95	(500.34)	104,453.69	-	104,453.69	-	104,453.69
Kinectrics Inc	Estimating the useful life of assets, report		39,000.00	-	-	39,000.00	-	39,000.00	-	39,000.00
	Participating LDC's share of the Kinectrics study (CIS Billings)			(16,000.00)	-	(16,000.00)	-	(16,000.00)	-	(16,000.00)
			39,000.00	(16,000.00)	-	23,000.00	-	23,000.00	-	23,000.00
Mercer Ltd.	IFRS consulting - Pension actuarial to IFRS				15,000.00	15,000.00	4,850.25	19,850.25	15,000.00	34,850.25
	TOTAL CONSULTING		**127,666.58**	**49,297.45**	**(2,447.84)**	**174,516.19**	**12,940.25**	**187,456.44**	**65,000.00**	**252,456.44**
Other incremental one time costs - Training										
	eIFRS online subscription service		388.65			388.65		388.65		388.65
	Risk Management & Governance Collection				63.25	63.25		63.25		63.25
	Training passports				4,960.00	4,960.00		4,960.00		4,960.00
	TOTAL TRAINING		**388.65**	**-**	**5,023.25**	**5,411.90**	**-**	**5,411.90**	**-**	**5,411.90**
Incremental Labour										
	incremental Finance staff		7,271.33	90,136.19	71,687.91	169,095.43	-	169,095.43	-	169,095.43
Cumulative interest on deferred asset			133.95	1,842.60	4,673.31	6,649.86	5,217.09	11,866.96	N/A	17,084.05
			135,460.51	**141,276.24**	**78,936.63**	**355,673.38**	**18,157.34**	**373,830.73**	**65,000.00**	**444,047.82**

Approval to Discontinue Variance Accounts 1518 and 1548

Question OEB 46

References: Exh 9, pp. 11 and 15, Table 9-3; Accounting Procedures Handbook ("APH"), Article 490, p.4

Article 490 of the APH states:

> *Retail Service Charges*
> *"Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the Retail Settlement Code ("RSC").*
>
> *The Board has reviewed practices in other industries and developed a set of estimates for distributors to charge for retail services with the understanding that the actual costs for providing these services may vary. Consequently, distributors are required to establish variance accounts to record the difference between the rates, charges or fees (collectively "approved rates") and the actual costs of providing these services.*
>
> *A distributor must establish at least two variance accounts for the purpose of recording variances between reasonable costs incurred for the provision of retail services and the rates for these services in their Board-approved rate order. These are:*
>
> *i. Retail Cost Variance Account for Retail Services (RCVA, Retail) , and*
>
> *ii. Retail Cost Variance Account for Service Transaction Requests (RCVA, STR).*

London Hydro is requesting the disposition of the account balances of $85,391 credit for Account 1518 and $89,918 for Account 1548 in Table 9-3 or net of $4,527 recoverable from customers. In addition, due to the insignificant net variance in the above two Retail Cost Variance Accounts (1518 and 1548) London Hydro is requesting the discontinuance of the use of these variance accounts.

*London Hydro used Account 1518 to record the net of revenues derived from establishing Service Agreements, distributor-consolidated billing, and the costs of entering into Service Agreements, and related contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the **incremental** costs incurred to provide the services described above, and the avoided cost credit arising from retailer consolidated billing. (emphasis added)*

*On the other hand, Account 1548 is being used to record the net of revenues derived, including accruals, from the Service Transaction Request services and charged by the distributor, and the **incremental** cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated. (emphasis added)*

a) *Please explain why London Hydro wants to deviate from the APH guidelines under Article 490 for accounts 1518 and 1548 and requesting the discontinuance of the use of accounts 1518 and 1548?*

b) Are the costs charged under these two accounts incremental costs? If they are incremental costs, please provide evidence to support this.

RESPONSE OEB 46:

a) The net variance of the two variance accounts is insignificant. *Ref. Exh. 9 / p. 11*

Table 9-2 – Retail Costs Variance Accounts Summary

Retail Cost Variance Accounts	Net Accruals / Variances	Carrying Charges	Ending Balances at Dec. 31, 2011	Projected Interest Jan 12 to Apr 30/13 - 1.47%	Projected Balances as at Apr 30/13
1518 Retail Cost Variance Account - Retail	$ (82,253)	$ (1,531)	$ (83,784)	$ (1,607)	$ (85,391)
1548 Retail Cost Variance Account - STR	86,736	1,488	88,224	1,694	89,918
	$ 4,483	**$ (43)**	**$ 4,440**	**$ 88**	**$ 4,528**

London Hydro would like to further respond to its request to deviate from the APH guidelines under Article 490 for accounts 1518 and 1548 and the discontinuance of the use of these accounts by referring to Board's Decision RP-2004-0117, RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064, dated December 9, 2004.

In the Decision, page 29, is the following:

"Board Findings

"4.0.12 APH490 is more current and clearly supersedes the Rate Handbook reference. However, given the relative insignificance of the balances in the RCVA accounts as revealed in this proceeding, the Board will not require recording and filing of this information if a distributor has not already done so. It is likely that the assessment of the reasonableness of the current charges for future consideration can be accomplished through filings by the present Applicants and by other distributors who plan to report balances in these deferral accounts. It may be that these accounts will not be needed in the future."

London Hydro requests consideration for the discontinuance of the RSVA accounts based on Board Decision and that the balances in the RSVA accounts of London Hydro reflect relative insignificance. In London's review of the Decision, it appears the Board has indicated insignificant RSVA balances permits a distributor to not be required to record or filing of this information.

b) London Hydro provides the following to demonstrate that Accounts 1518 and 1548 reflect incremental costs. The revenues and costs reflected in schedules are those for quarter ending September 30, 2012 and for period January 1, 2012 to September 30, 2012.

2.1.1 Retail Services and Settlement Variances

Monitoring Requirements For RCVA per Chapter 11 of the Rates Handbook

REVENUES - Quarter September 30, 2012

Service Description	Charge Per Unit ***	Number of Units	Unit Measure	Total Revenue (credit)
Section 1 - Service Agreements				
Standard Charge	$ 100.00	0	One time charge per retailer	$ -
Monthly Fixed Charge	$ 20.00	60	Per month per retailer	$ (1,200.00)
Monthly Variable Charge	$ 0.50	40,750	Per month per customer	$ (20,375)
Section 2 - Distributor Consolidated Billing				
Bill - ready billing	$ 0.30	40,358	Per month per customer	$ (12,107)
Rate - ready billing		-		$ -
Section 3 -Retailer Consolidated Billing				
Avoided Cost Credit	$ (0.30)	-	Per month per customer	$ -
Section 4 - Split Billing				
Split Billing		-		
			TOTAL (Account 4082)	$ (33,682)

Service Description	Charge Per Unit ***	Number of Units	Unit Measure	Total Revenue (credit)
Section 6 - Service Transaction Request				
Request Fee	$ 0.25	2,220	Per request	$ (555)
Processing Fee	$ 0.50	1,154	Per request	$ (577)
Information delivery charge - other than EBT	$2.00 plus any incremental delivery costs	-	Per request greater than 2 requests	$ -
Section 8 - Retailer Settlement Payment Default				
Request Fee	$ 0.25	-	Per request	$ -
Processing Fee	$ 0.50	-	Per request	$ -
Section 7 - Other associated costs to be recovered - Please specify				
				$ -
				$ -
			TOTAL (Account 4084)	$ (1,132)

INCREMENTAL COSTS INCURRED

Accounts where costs recorded	Cumulative Incremental Cost				Account Balance to date
	For Qtr ending: September 30, 2012		For the Period from Jan 1 to September 30, 2012		
	Retail Services Related $	STR Related $	Retail Services Related $	STR Related $	
5315	28,453.28	9,129.54	$ 102,557	$ 27,506	$ 130,063
					$ -

*** Charges per unit according to Chapter 11 of the Rate Handbook

Summary of Revenues $ Expenses	Rate	Monthly Expense	Q3 - 2012 Exp	Q3 - 2012 Rev	Net
Retailer Charges 1518					
Standard One Time Charge	$ 100.00	$ -	$ -	$ -	
Retailer Monthly Fixed Charge	20.00	175.00	525	(1,200)	
Retailer Monthly Variable Charge	0.50	6,744.80	20,234	(20,375)	
LDC Consolidated Billing Charge	0.30	2,564.63	7,694	(12,107)	
Avoided cost credits	(0.30)	-	-	-	
		$ 9,484	$ 28,453	$ (33,682)	$ (5,229)
STR Charges 1548					
STR - Request Fees	$ 0.25	$ 1,521.59	$ 4,565	$ (555)	
STR - Processing Fees	0.50	1,521.59	$ 4,565	(577)	
STR - Information Request Fee	2.00		$ -	-	
		$ 3,043	$ 9,130	$ (1,132)	$ 7,998
		Totals	$ 37,583	$ (34,814)	$ 2,768

Retailer Charges

Standard One-Time Charge **$100.00 per agreement per Retailer**

The Standard Charge is a one-time charge and is intended to recover the costs of entering into the service agreement required by the RSC

Monthly Fixed Charge **$20.00 per month per retailer**

The Monthly Fixed Charge is intended to recover the cost of contract administration, and monitoring prudential requirements

Contract Administration
Set up as a monthly "Regular Charge" in CIS
Charge applied to the Retailer's account on the 1st of each month automatically by the system
Update Service Agreement, Retailer Contact Information i.e. contacts, phone numbers, mailing address, etc.

Retailer Prudential
- Request Retailer reports from Rakesh
- Verify calculations by Retailer
- Prepare Retailer Prudential spreadsheets
- Create Retailer letter
- E-mail and send by courier a copy of the Prudential package to each Retailer
- Update Retailer database i.e. cash and or CIS i.e. letter of credit
- Update Retailer Prudential tracking database
- Finance alerted of all cash deposits
- Finance calculates Prudential interest monthly
- Finance updates Prudential interest spreadsheet
- Collections follows up on all letters of credit i.e. expiry/renewals

Function	Mthly Time - hours	Rate	Systems Involved	Mthly Costs	Annual Costs
Contract Administration	0.50	$ 30.00	CIS/Excel	$ 15.00	$ 180.00
Prudential					
Request Reports	0.00	30.00	Crystal	-	-
Verify Calculations	0.50	30.00		15.00	180.00
Prepare spreadsheets	0.50	30.00		15.00	180.00
Retailer letter	0.50	30.00		15.00	180.00
E-mail/Courier	0.50	30.00		15.00	180.00
Courier costs	12.04 per unit	30.00	Purolator	70.00	840.00
Update database	0.25	30.00	CIS	7.50	90.00
Update database	0.25	30.00	Excel	7.50	90.00
Calculate Interest	0.25	30.00		7.50	90.00
Update Interest spreadsheet	0.25	30.00		7.50	90.00
				$ 175.00	$ 2,100.00

Monthly Variable Charge **.50 per month per customer**

The Monthly Variable Charge is intended to recover costs related to the general accounting; administration services and other communication and customer care service necessary to maintain the contract.

Administrative Services

- Print Reports to determine the number of customers
- Update "Retailer Monthly Charges" spreadsheet
- Create a manual account transaction for each Retailer
- Karen F to approve all manual account transactions
- Verify and validate IST/IMP totals
- Update IST/IMP spreadsheets
- Print weekly IST report to verify totals
- Send copy to Karen F and Finance (Kevin W)
- Kevin creates EFT file based on spreadsheet
- Create manual account transactions "EBT Monthly Retailer Variable charge"
- Look for incoming payments i.e. wire transfer, EFT, etc.
- Advise Head Cashier to process all payments

Function	Mthly Time - hours	Rate	Systems Involved	Mthly Costs	Annual Costs
Print Reports	0.50	$ 30.00	CIS	$ 15.00	$ 180.00
Update spreadsheet	1.00	30.00	Excel	30.00	360.00
Create manual account transactions	1.00	30.00	CIS	30.00	360.00
Karen to approve	0.50	30.00	CIS	15.00	180.00
Verify and validate IST/IMP totals/Update Spreadsheet	0.22	30.00	CIS/Access/Excel	6.60	79.20
Print weekly IST report	5.00	30.00	CIS	150.00	1,800.00
SFT file created	0.80	30.00	TD - Windows	24.00	288.00
Process payments	20.00	30.00	TD - Windows	600.00	7,200.00
SPI monthly charges	1.00	1,674.20	SPI	1,674.20	20,090.36
SPI yearly maintenance	1.00	-	SPI	-	-
London Hydro sys tem maintenance				-	-
London Hydro server				-	-
Processing of daily transactions (inbound and outbound)	20.00	30.00	Workflow / CIS	600.00	7,200.00
Working exceptions (rejects and failures)	40.00	30.00	Workflow / CIS / SPI	1,200.00	14,400.00
Manual workaround sys tem issues	40.00	30.00	Workflow / CIS / SPI	1,200.00	14,400.00
Inquiries from Retailers	40.00	30.00	Workflow / CIS / SPI	1,200.00	14,400.00
				$ 6,744.80	$ 80,937.56

Standard Distribution-Consolidated Billing Charge	$1 per month per customer

The charge is intended to recover the incremental costs incurred by a distributor in providing a distributor-consolidated bill-ready service. This charge will be collected from the retailer

Billing Services

We place competitive energy charge provided from the Retailer on a customer's A/R
Provide a bill message and a dollar amount supplied by the Retailer
Send the customer a bill i.e. mail, fax, e-mail, etc.
Collect all charges applicable to the bill
Print Reports to determine the number of customers
Update "Retailer Monthly Charges" spreadsheet
Create manual account transactions for each Retailer
Karen F to approve all manual account transactions

Function	Mthly Time - hours	Rate	Systems Involved	Mthly Costs	Annual Costs
Processing IBRs to create service account transactions for billing	Dev costs to convert IBRs	$300,000 over 5 years	CIS	$ -	$ -
Bill Print-the Retailers line DOS customers	1.2661	0.12	CIS/Quallech	1,604.63	19,255.56
Mailing of bills	2.00	30.00	Quallech	-	-
Bill payments	2.00	30.00	RCS / CIS	-	-
Collections	2.00	30.00	CIS / phones	-	-
Billing inquiries	2.00	30.00	CIS / phones	-	-
Print Reports	0.50	30.00	CIS	15.00	180.00
Update spreadsheet	0.50	30.00	Excel	15.00	180.00
Create manual account transactions	1.00	30.00	CIS	30.00	360.00
Inquiries from London Hydro staff re. customer questions	30.00	30.00	Workflow/CIS/SPI	900.00	10,800.00
				$ 2,564.63	$ 30,775.56
		Average cost per transaction		$ 0.09	

Avoided Cost Credit	$1 per month per customer (credit)

Under this option, a distributor shall not directly bill a customer and as a result, should be able to avoid certain costs (eg. mailing). Hence, an avoided cost credit will be available to retailers against the monthly variable charge. Credit available to a retailer

The costs avoided should equal the incremental costs identified to provide the services.
Thus total avoided costs are estimated to the number of transactions avoided times the average transaction cost.

Total transactions for the period		-
Avoided cost per transaction	$	0.09
Total avoided cost	$	-
Total credits given to retailers	$	-

STR CHARGES

Request Fee	$2 per request

This fee will apply once an STR is placed regardless of whether that STR can be processed. It is intended to recover costs incurred by a distributor for the initial screening process of an STR, as required under section 10.4 of the RSC. This fee will apply to the requesting party.

Still Request Fees
Process transactions
Send acknowledgement i.e. Accept/Reject
Charges generated by the system and placed on the Retailer's A/R

Total Actual Costs Charged:

Function	Mthly Time - hours	Rate	Systems Involved	Mthly Costs	Annual Costs
Processing transactions	development cost over 5 years		SPI/EBT/Workflow	1,521.59	18,259.05
Send acknowledgement	0.00	-	CIS	-	-

LRAMVA

Question OEB 47

References

i. *Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13: LRAM*
ii. *Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications, Last Revised on June 28, 2012, Section 2.7.10: CDM Costs*
iii. *Exh 1, p. 33 and Exh 4, p. 135*

London notes that it has elected not to file an LRAMVA claim with this application, but rather defer its claim until its 2014 rate application.

As stated in Section 13.4 of the Board's Guidelines for Electricity Distributor Conservation and Demand Management, April 26, 2012 (EB-2012-0003) and section 2.7.10 – CDM Costs, LRAMVA, Pages 36-37 of the Filing Requirements, at a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications.

Please provide the evidence supporting the disposition of your LRAMVA – Account 1568 balance as of December 31, 2011. Please ensure that the evidence comprises the elements listed below.

i) Full LRAMVA calculations that are based on the final evaluation results for 2011 OPA-Contracted Province-Wide CDM Programs ("OPA Programs"). The LRAMVA calculations are determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;

ii) Separate tables for each rate class that shows the LRAMVA amounts requested in association with the final evaluation results for 2011 OPA Programs;

iii) A statement that indicates the amount, if any, that London's last approved load forecast was adjusted to reflect forecasted CDM impacts in association with London's 2011-2014 CDM Targets;

iv) Calculations showing the variance, if any, between the CDM component related to the 2011-2014 CDM Targets included in London's last approved load forecast and the final evaluation results for London's 2011 OPA Programs;

v) A statement indicating that the distributor has relied on the most recent final evaluation report from the OPA in support of its LRAMVA calculation;

vi) A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAMVA amount;

vii) Applicable LRAMVA rate riders for all affected rate classes;

viii) A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAMVA amount; and

ix) Documentation of the distributor's final evaluation results for its 2011 OPA Programs.

Response OEB 47

i) London Hydro has now received its OPA report on the final 2011 OPA CDM program results, and is now able to proceed with applying for LRAM for 2011 OPA CDM Programs.

Based on OPA's report, contained in the submission as an excel file, LondonHydro_Copy of 2011_Final_ Annual_ Report_ Data_ CDM_ OPAPrograms_20130108 calculations for determining LRAM have been made in Appendix C: London Hydro 2013 LRAM for 2011 CDM Programs Recoveries Rate Application. Included in this appendix are full LRAMVA calculations that are based on the 2011 final evaluation results for 2011 OPA-Contracted Province-Wide CDM Program report, using the energy savings by customer class and valuing those energy savings using London Hydro's Board-approved variable distribution charge appropriate to the class.

The amount associated with 2011 OPA CDM Programs that the Applicant seeks to recover through volumetric rate riders totals a LRAM amount of $176,092, including carrying costs.

ii) Separate tables for each rate class is provided in Appendix C: London Hydro 2013 LRAM for 2011 CDM Programs Recoveries Rate Application that show LRAM amounts requested with the final evaluation results for 2011 OPA Programs.

The following reflects the results as indicated in Appendix C:

London Hydro Inc.
OPA CDM Program Load Impacts (2011)

2011 Data from OPA Verfied Results
see Tab 1- OPA CDM Savings

*London Hydro is not requesting LRAM /SSM for Programs in 2006, 2007, and 2008. Programs in 2009 were also not included

		2011 NET		2011 GROSS		2012 NET		2012 GROSS		TOTAL NET		TOTAL GROSS	
Class/ Program	Year Program Implimented	kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw
RESIDENTIAL													
Appliance Retirement	2011	1,002,610	167.0	1,967,720	350.0	1,002,610	167.0	2,471,000	395.0	2,005,220	334.0	4,438,720	745.0
Appliance Exchange	2011	15,910	12.0	30,871	24.0	15,910	12.0	2,855,000	1,826.0	31,820	24.0	2,885,871	1,850.0
HVAC Incentives	2011	1,901,868	1,052.0	3,173,112	1,739.0	1,901,868	1,052.0	1,159,000	112.0	3,803,736	2,104.0	4,332,112	1,851.0
Conservative Instant Coupon Booklet	2011	512,644	32.0	465,107	28.0	512,644	32.0	1,159,000	112.0	1,025,288	64.0	1,624,107	140.0
Bi-Annual Retailer Event	2011	802,521	46.0	734,572	41.0	802,521	46.0	1,159,000	112.0	1,605,042	92.0	1,893,572	153.0
Residential Total		**4,235,553**	**1,309.0**	**6,371,382**	**2,182.0**	**4,235,553**	**1,309.0**	**8,803,000**	**2,557.0**	**8,471,106**	**2,618.0**	**15,174,382**	**4,739.0**
General Service < 50 kW													
OPA Energy Retrofit Incentive Program (ERIP)	2010	797,576	111.4	1,329,017	187.6	797,576	111.4	1,329,017	187.6	1,595,151	222.9	2,658,033	375.2
High Performance New Construction*	2010	865,905	169.0	1,731,809	337.0	865,905	169.0	1,731,809	337.0	1,731,810	338.0	3,463,618	674.0
Efficiency Equipment Replacement	2011	493,355	95	657,805	130	493,355	95	657,805	129.6	986,710	190.6	1,315,610	259.1
Direct Install Lighting	2011	145,929	56.0	157,160	52.0	145,929	368.0	1,198,000	525.0	291,858	424.0	1,355,160	577.0
Demand Response 3	2011	19,012	485.0	19,012	642.0	0	0.0	0	0.0	19,012	485.0	19,012	642.0
Total General Service < 50 kW		**2,321,777**	**917**	**3,894,802**	**1,348**	**2,302,765**	**744**	**4,916,630**	**1,179.2**	**4,624,542**	**1,660.4**	**8,811,433**	**2,527.4**
General Service 50 kW to 4,999 kW													
OPA Energy Retrofit Incentive Program (ERIP)	2010	8,928,955	1,247.6	14,878,502	2,100.4	8,928,955	1,247.6	14,878,502	2,100.4	17,857,911	2,495.1	29,757,005	4,200.8
Efficiency Equipment Replacement	2011	5,523,172	1,066.7	7,364,206	1,450.4	5,523,172	1,066.7	7,364,206	1,450.4	11,046,344	2,133.4	14,728,412	2,900.9
Demand Response 3	2011	125,454	2,137.0	125,454	2,536.0	0	0.0	0	0.0	125,454	0.0	125,454	0.0
Total General Service 50 to 4,999 kW		**14,577,581**	**4,451.3**	**22,368,163**	**6,087**	**14,452,127**	**2,314**	**22,242,709**	**3,550.8**	**29,029,708**	**4,628.6**	**44,610,871**	**7,101.6**
Total Load Impacts from OPA programs		**21,134,911**	**6,677**	**32,634,347**	**9,617**	**20,990,445**	**4,367**	**35,962,339**	**7,287**	**42,125,356**	**8,907**	**68,596,686**	**14,368**

Forgone Revenue by Program and Class

*London Hydro is not requesting LRAM /SSM for Programs in 2006, 2007, and 2008. Programs in 2009 were also not included

		2011				2012				Total Revenue
Class/ Program	Year Program Implimented	Load Impact	kWh or kW	Rate per Unit	Revenue	Load Impact	kWh or kW	Rate per Unit	Revenue	
RESIDENTIAL										
Appliance Retirement	2011	1,002,610	kWh	$ 0.0142	$ 14,237.06	1,002,610	kWh	$ 0.0143	$ 14,337.32	$ 28,574.39
Appliance Exchange	2011	15,910	kWh	$ 0.0142	$ 225.92	15,910	kWh	$ 0.0143	$ 227.51	$ 453.44
HVAC Incentives	2011	1,901,868	kWh	$ 0.0142	$ 27,006.53	1,901,868	kWh	$ 0.0143	$ 27,196.71	$ 54,203.24
Conservative Instant Coupon Booklet	2011	512,644	kWh	$ 0.0142	$ 7,279.54	512,644	kWh	$ 0.0143	$ 7,330.81	$ 14,610.35
Bi-Annual Retailer Event	2011	802,521	kWh	$ 0.0142	$ 11,395.80	802,521	kWh	$ 0.0143	$ 11,476.05	$ 22,871.85
Residential Total		**4,235,553**			**$ 60,144.85**	**4,235,553**			**$ 60,568.41**	**$ 120,713.26**
General Service < 50 kW										
OPA Energy Retrofit Incentive Program (ERIP)	2010	797,576	kWh	$ 0.0091	$ 7,257.94	797,576	kWh	$ 0.0092	$ 7,337.69	$ 14,595.63
High Performance New Construction*	2010	865,905	kWh	$ 0.0091	$ 7,879.74	865,905	kWh	$ 0.0092	$ 7,966.33	$ 15,846.06
Efficiency Equipment Replacement	2011	493,355	kWh	$ 0.0091	$ 4,489.53	493,355	kWh	$ 0.0092	$ 4,538.87	$ 9,028.40
Direct Install Lighting	2011	145,929	kWh	$ 0.0091	$ 1,327.95	145,929	kWh	$ 0.0092	$ 1,342.55	$ 2,670.50
Demand Response 3	2011	19,012	kWh	$ 0.0091	$ 173.01	0	kWh	$ 0.0092	$ -	$ 173.01
	2011	0	kWh	$ 0.0091	$ -	0	kWh	$ 0.0092	$ -	$ -
Total General Service < 50 kW		**2,321,777**			**$ 21,128.17**	**2,302,765**			**$ 21,185.44**	**$ 42,313.60**
General Service 50 kW to 4,999 kW										
OPA Energy Retrofit Incentive Program (ERIP)	2010	1,247.6	kW	$ 1.6081	$ 2,006.20	1,248	kW	$ 1.6223	$ 2,023.92	$ 4,030.12
Efficiency Equipment Replacement	2011	1,066.7	kW	$ 1.6081	$ 1,715.39	1,067	kW	$ 1.6223	$ 1,730.53	$ 3,445.92
Demand Response 3	2011	2,137	kW	$ 1.6081	$ 3,436.51	0	kW	$ 1.6223	$ -	$ 3,436.51
Total General Service 50 to 4,999 kW		**4,451**			**$ 7,158.10**	**2,314**			**$ 3,754.45**	**$ 10,912.55**
Total Forgone Revenue OPA programs		**6,561,781**			**$ 88,431.12**	**6,540,632**			**$ 85,508.30**	**$ 173,939.42**

iii) London's last approved load forecast was approved as part of London's 2009 COS application. The approved load forecast did not include a component relating to the programs associated with achieving the 2011-2014 CDM targets. As a result, the variance calculation for 2011 which relates to the 2011-2014 CDM targets would be the final evaluation results for London's 2011 OPA Programs minus zero.

iv) See Q# 47 iii). London Hydro's last approved load forecast was in 2009 which did not include adjustments for CDM impacts in association with London Hydro's 2011 – 2014 CDM Targets.

v) London Hydro confirms it has relied on the most recent final evaluation report Copy of 2011_Final_ Annual_ Report_ Data_ CDM_ OPAPrograms_20130108 from the OPA in supporting its LRAM calculation. A copy of the OPA report (for year 2011) can be sourced in Appendix C: London Hydro 2013 LRAM for 2011 CDM Programs Recoveries Rate Application

vi) London Hydro has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount.

vii) The applicable LRAM rate riders associated with 2011 CDM programs, and as determined in excel LondonHydro_LRAMVA_2011_Bdstaff IR Q # 47 _ 20130108, are as follows:

Class	Units	LRAM	Carrying Charges	Total	2011 Billing Determines	Rate Rider
Residential	kWh	$ 120,713	$ 1,476	$ 122,190	1,128,904,736	$ 0.00011
GS < 50 kW	kWh	$ 42,314	$ 518	$ 42,832	408,115,902	$ 0.00010
GS 50 to 4,999 kW	kW	$ 10,913	$ 159	$ 11,071	3,944,476	$ 0.00281
Totals		$ 173,939	$ 2,152	$ 176,092		

Billing Deteminates used 2011 Distribution Energy Quantities (Actual)

viii) London Hydro is requesting recoveries for carrying charges applicable to LRAM amounts determined for 2011 OPA CDM Programs.

London Hydro has based its carrying charges on the Toronto Hydro Decision, in which the Board found that Toronto Hydro was entitled to carrying charges on the LRAM balances. London Hydro has calculated carrying charges as follows: interest has been applied to the ending balance of the annual LRAM

for all of 2011 and 2012. The calculation of the carrying costs used the Board's prescribed interest rates for Q1 2011 – Q1 2013, as shown below:

	Q1 2012	Q2 2012	Q3 2012	Q4 2012	4 Months to April 30, 2013	Total
%	1.47	1.47	1.47	1.47	1.47	
Residential ($)	$ 221	$ 221	$ 221	$ 221	$ 591	$ 1,475.62
GS < 50 kW ($)	$ 78	$ 78	$ 78	$ 78	$ 207	$ 517.92
GS 50 to 4,999 kW ($)	$ 26	$ 26	$ 26	$ 26	$ 53	$ 158.70

London Hydro is seeking a total of $2,152 for carrying charges.

ix) London Hydro once again states that it has relied on the most recent final evaluation report Copy of 2011_Final_ Annual_ Report_ Data_ CDM_ OPAPrograms_20130108 from the OPA in supporting its LRAM calculation. A copy of the OPA report (for year 2011) can be sourced in Appendix C: London Hydro 2013 LRAM for 2011 CDM Programs Recoveries Rate Application.

Balances for Disposition

Question OEB 48

References:

i. Exh 9, p. 15 (Table 9-3);

ii. Appendix 9-A, p. 44

Account 1595 has carrying charges of $286,860 (credit to customers), but appears to have no principal balance on December 31, 2011.

Please explain the $286,806 credit balance and provide a detailed calculation of the carrying charges, principal and the interest rates used for the balance of ($286,860).

Response OEB 48

Account 1595 Disposition and Recovery of Regulatory Balances Control Account Sub-account Disposition of Account Balances Approved in 2009 reflects the residual balances approved for disposition with the previous COS proceedings EB-2008-0235. The full amount of principal was refunded to the customers, and the residual balance consists of interest only.

Schedule of Account 1595 Disposition and Recovery of Regulatory Balances Control Account Sub-account Disposition of Account Balances Approved in 2009

Date	Account 1595 Opening Balance	Principal Recoveries/ Refunds	Closing Principal Balance	Days	Interest Rate	Interest Earned After Sept 30/09	Interest Recoveries	Transfers IN - Interest	Closing Interest Balance	Account 1595 Closing Balance	Actual Recoveries/ Refunds for the Period
31-Aug-09	-	-	-	31	0.55%	-	-	-	-	-	
30-Sep-09	-	-	-	30	0.55%	-	-	-	-	-	
31-Oct-09	(7,075,045)	16,617	(7,058,428)	31	0.55%	(3,304.92)	-	(490,487)	(493,792)	(7,552,219)	16,617
30-Nov-09	(7,058,428)	309,241	(6,749,187)	30	0.55%	(3,190.80)	-	-	(496,983)	(7,246,170)	309,241
31-Dec-09	(6,749,187)	299,264	(6,449,923)	31	0.55%	(3,152.70)	-	-	(500,135)	**(6,950,058)**	299,264
31-Jan-10	(6,449,923)	421,499	(6,028,424)	31	0.55%	(3,012.91)	-	-	(503,148)	(6,531,573)	421,499
28-Feb-10	(6,028,424)	382,471	(5,645,953)	29	0.55%	(2,634.34)	-	-	(505,783)	(6,151,736)	382,471
31-Mar-10	(5,645,953)	436,290	(5,209,663)	31	0.55%	(2,637.36)	-	-	(508,420)	(5,718,083)	436,290
30-Apr-10	(5,209,663)	364,388	(4,845,275)	30	0.55%	(2,355.05)	-	-	(510,775)	(5,356,050)	364,388
31-May-10	(4,845,275)	352,821	(4,492,454)	31	0.55%	(2,263.34)	-	-	(513,038)	(5,005,492)	352,821
30-Jun-10	(4,492,454)	395,105	(4,097,349)	30	0.55%	(2,030.84)	-	-	(515,069)	(4,612,418)	395,105
31-Jul-10	(4,097,349)	419,332	(3,678,016)	31	0.89%	(3,097.15)	-	-	(518,166)	(4,196,183)	419,332
31-Aug-10	(3,678,016)	456,570	(3,221,446)	31	0.89%	(2,780.18)	-	-	(520,946)	(3,742,393)	456,570
30-Sep-10	(3,221,446)	436,366	(2,785,080)	30	0.89%	(2,356.51)	-	-	(523,303)	(3,308,383)	436,366
31-Oct-10	(2,785,080)	392,422	(2,392,658)	31	1.20%	(2,838.49)	-	-	(526,141)	(2,918,799)	392,422
30-Nov-10	(2,392,658)	358,412	(2,034,245)	30	1.20%	(2,359.88)	-	-	(528,501)	(2,562,747)	358,412
31-Dec-10	(2,034,245)	343,234	(1,691,012)	31	1.20%	(2,073.26)	-	-	(530,575)	**(2,221,586)**	343,234
31-Jan-11	(1,691,012)	416,249	(1,274,762)	31	1.47%	(2,111.22)	-	-	(532,686)	(1,807,448)	416,249
28-Feb-11	(1,274,762)	362,141	(912,621)	28	1.47%	(1,437.51)	-	-	(534,123)	(1,446,745)	362,141
31-Mar-11	(912,621)	424,901	(487,721)	31	1.47%	(1,139.40)	-	-	(535,263)	(1,022,983)	424,901
30-Apr-11	(487,721)	348,112	(139,609)	30	1.47%	(589.27)	-	-	(535,852)	(675,461)	348,112
31-May-11	(139,609)	139,609	-	31	1.47%	(174.30)	211,518	-	(324,508)	(324,508)	351,127
30-Jun-11	-	-	-	30	1.47%	-	34,288	-	(290,220)	(290,220)	34,288
31-Jul-11	-	-	-	31	1.47%	-	4,329	-	(285,891)	(285,891)	4,329
31-Aug-11	-	-	-	31	1.47%	-	(22)	-	(285,913)	(285,913)	(22)
30-Sep-11	-	-	-	30	1.47%	-	179	-	(285,734)	(285,734)	179
31-Oct-11	-	-	-	31	1.47%	-	(81)	-	(285,815)	(285,815)	(81)
30-Nov-11	-	-	-	30	1.47%	(0.10)	(960)	-	(286,775)	(286,775)	(960)
31-Dec-11	-	-	-	31	1.47%	(1.30)	(83)	-	(286,860)	**(286,860)**	(83)

Question OEB 49

References

- *i. Exh 1, p.15;*
- *ii. Exh 9, p.2;*
- *iii. Accounting Procedures Handbook (APH): Article 210, p. 23: 7000 account series;*
- *iv. APH FAQ #3, July 2012; Addendum to Report of the Board: Implementing International Financial Reporting Standards (IFRS) in an Incentive Rate Mechanism Environment dated June 13, 2011 (EB 2008-0408), pp. 23-24*

The Addendum to Report of the Board on Implementing IFRS states:

> *"With respect to P&OPEB items, the Board is not persuaded that a generic account is necessary. It is not clear that the impact of the transition to IFRS on P&OPEB Items will be consistent among Ontario utilities. Individual utilities that can demonstrate the likelihood of large variances can seek an individual variance account from the Board.*
>
> *If it becomes apparent over time that utilities are generally experiencing material, unpredictable variances in these items, the Board will consider solutions in its development of rate-setting mechanisms.''*

The July 2012 APH Q & A #3 states:

> *"Electricity distributors are required to annually open new sub-accounts of Account 1595, Disposition and Recovery/Refund of Regulatory Balances. New accounting procedures for Account 1595 are provided in the revised 2012 APH in Article 220. The account description of (control) Account 1595 specifies that for each year the deferral or variance account balances are approved for disposition by the Board, distributors are required to set-up under the control account three sub-accounts using the format of a vintage year classification of the year in which the balances are approved for disposition and recovery from or refund to customers.*
> *The three sub-accounts are as follows:*
>
> *1. Sub-account Principal Balances Approved in "20yy"*
> *2. Sub-account Carrying Charges Approved in "20yy"*
> *3. Sub-account Carrying Charges for Net Principal in "20yy"*

London Hydro is requesting three new Deferred and Variance Accounts (DVA):

I. To record re-measurement recognized in Other Comprehensive Income (OCI) such as the MIFRS post-employment benefit adjustment.

II. To record the recovery and refunds pertaining to the disposition of the deferral and variance accounts at December 31, 2011 including carrying charges forecasted to April 30, 2013 under sub account 1595 for Global Adjustment (GA).

III. To record the recovery and refunds pertaining to the disposition of the deferral and variance accounts at December 31, 2011 including carrying charges forecasted to April 30, 2013 under sub account 1595 for all other DVAs other than GA.

Questions / Requests

a) For part "I", please clarify what London Hydro means by "re-measurement recognized in Other Comprehensive Income (OCI) such as the MIFRS post - employment benefit adjustment".

b) Please explain why London Hydro require a new DVA account for part "I".

c) The APH has established Uniform System of Accounts (USoA) for OCI, in particular the 7000 account series. Given this, why does London Hydro need a new separate DVA for the re-measurement in OCI for the MIFRS post-employment benefit adjustment?

d) With regards to the projected variance in the new DVA account requested in part "I", what is London Hydro's estimate in $ and how material is this amount?

e) For part "II" and "III", please confirm that London Hydro will be following the guidelines provided in the APH FAQ #3, July 2012 for the two sub

accounts requested under account 1595 for GA and for all other DVAs other than GA.

Response OEB 49

a) Where London Hydro refers to "re-measurement recognized in Other Comprehensive Income ("OCI") such as the MIFRS post – employment benefit adjustment" on page 15 of Exhibit 1, it was referring to the one-time Pension and Other Post-Employment Benefits adjustment to be made at the time of transition to IFRS. This one-time transitional adjustment is currently $1,844,800 as indicated in Exhibit 10, page 21 and as also referenced below under Question 58.

b) As addressed below under Question 58, Addendum to Report of the Board: Implementing International Financial Reporting Standards (IFRS) in an Incentive Rate Mechanism Environment EB 2008-0408 dated June 13, 2011, pp. 23-24 states that "Individual utilities that can demonstrate the likelihood of large variances can seek an individual variance account from the Board."

   Since the transitional P&OPEB adjustment is a material amount ($1,844,800), London Hydro is requesting that a deferral account be opened for use when the Company does in fact move to IFRS.

c) London Hydro is requesting a deferral account for the one-time P&OPEB transitional adjustment noted above so that it can be amortized for rate making purpose over a period greater than one year.

   This transitional adjustment is an adjustment to the opening balance sheet on transition to IFRS, rather than a charge to OM&A for a given year. It is London Hydro's understanding that the newly established 7000 account series are for the purposes of recording activities for one year. As discussed in Exhibit 10, this adjustment represents the difference in the Company's liability under IFRS in comparison to that calculated under CGAAP as at January 1, 2012 and represents unamortized actuarial losses and an unrecognized liability associated with future benefits relating to service awards.

d) As indicated above, the estimate dollar amount of this one-time transitional adjustment is $1,844,800 which is material. The materiality limited for the 2012 Bridge Year under CGAAP is $349,000.

e) London Hydro confirms that it will be fully following the guidelines as provided in APH FAQ #3 July 2012 for both sub-accounts, 1595 for Global Adjustment (GA) and sub-account 1595 for all other DVAs other than GA.

Account 1588

Question OEB 50

Reference: EB-2012-0380 pre-filed evidence filed September 25, 2012, p. 10 / Table 2

London Hydro has noted $3.8 million debit and credit adjustments to Account 1588

a) Please confirm the error related to $3.8 million for Account 1588 is related to the balances from December 31, 2008 to June 30, 2012. If not, please explain.

b) Please provide the journal entries (both sides – debits and credits) made in June 2012 to reflect the adjustments made to Account 1588, involving the $3.8 million debit to Account 1588 sub-account GA and the $3.8 million credit to the control account of Account 1588.

Response OEB 50

Please reference Appendix D – RSVA Commodity Variance Accounts – Unbilled Energy Calculation Review 1588 RSVA Power and RSVA Power Sub-account Global Adjustment ("RSVA background document"), which is also identified in Board staff Q# 52, *before reading* the response to this question.

a) 1588 Power:

The $3.8 Million relates to the balances as at December 31, 2010. This is the amount accrued for the RPP portion of energy price adjustment on the unbilled energy at December 31, 2010 via reversing journal entry, which is the equivalent with the remaining settlement amount with the IESO.

dr 4705 Power Purchased	$3,806,100
cr 2205 Accounts Payable	($3,806,100)

Fixed price energy debit/credit on unbilled amounts

dr 1588 RSVA Power	$3,806,100
cr 4705 Power Purchased	($3,806,100)

Close off to RSVA - fixed price energy debit/credit on unbilled amounts

London Hydro has determined there is no error associated with the 1588 Power account as at December 31, 2010 and initially reported values are correct.

1588 Power Sub-account Global Adjustment:

The $3.8 Million relates to the balances as at December 31, 2010. This is the amount accrued for the RPP portion of Global Adjustment claim on the unbilled energy at December 31, 2010 via reversing journal entry.

dr 2205 Accounts Payable	$3,802,961
cr 4707 Charges – Global Adjustment	($3,802,961)

GA credit on unbilled amounts

dr 4707 Charges – Global Adjustment	$3,802,961
cr 1588 RSVA Power Sub-account Global Adjustment	($3,802,961)

Close off to RSVA - GA credit on unbilled amounts

This $3.8 Million should not have been accrued (as discussed in the RSVA Background Document) as the prorated / accrual method is already being followed and therefore the additional accrual is not required.

b) As a result of the findings discussed in the RSVA Background Document the quarterly RRR filings for 2012 will be requested for resubmission to the OEB.

London Hydro is requesting the disposition of the 1588 accounts based on balances as at December 31, 2011 (audited) balances and therefore the June 30, 2012 balances are no longer relevant.

Question OEB 51

Reference: EB-2012-0380 pre-filed evidence filed September 25, 2012 / p. 9.

London Hydro stated on page 9 of the pre-filed evidence filed on September 25, 2012 that "as a result of this accounting error [an] incorrect account balance was submitted for approval for disposition in the 2012 IRM proceeding…"

a) In which fiscal period was the fixed price debits/credits calculated and first included twice in the unbilled energy period end balance? Please explain.

b) How far back was this error made? Please specify the date and summarize the dollar impact to the Account 1588 control account and Account 1588 sub-account GA on an annual basis in a table format.

c) Does the inaccurate presentation of Account 1588 control account and Account 1588 sub-account GA impact the December 31, 2008 balances cleared in the 2009 Cost of Service proceeding, in addition to the December 31, 2010 balances cleared in the 2012 IRM proceeding? Please explain.

Response OEB 51

Please reference the RSVA background document found in Appendix D and referenced in Board staff Q # 52, before reading the response to this question.

a) The 1588 Power Sub-account Global Adjustment double accrual started in August 2010 upon the implementation of the accrual method. The reversing accrual entry at the end of December 2010 was made for $3,802,961 for RPP related Global Adjustment credit. This entry is not required, since the credit was calculated based on the accrual method described in response to question OEB 52a) in the Review Report Amendment.

1588 RSVA Power account has no error. The reconciliation of the RPP price difference is completed on a forward basis, and therefore, the accrual entry for the unbilled portion has to be accrued in addition to the trade month IESO unpaid invoice for the month-end to arrive at the result of the accrual method. The accrual entry accounts for this outstanding amount and moves it to Accounts Payable due to the IESO.

b) As described in the Review report Amendment (response to question OEB 52a), the error occurred only in the 1588 Power Sub-account Global Adjustment commencing in Year 2010.

1588 RSVA Power Sub-account Global Adjustment as filed and reconciled to RRR 2.1.7

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Credits	Total Net Accruals	Board Approved Disposition	Closing Balance	RRR 2.1.7	Variance	
No fixed price credit accrued in Year 2008				-	-					
Year 2009	1,982,029	8,365	5,408,166	(4,262,161)	1,146,005	(2,001,899)	1,134,500	1,134,500	0	*Note 1.*
Year 2010	1,134,500	(2,644)	(2,882,212)	459,200	(2,423,013)	-	**(1,291,157)**	(1,291,157)	0	
Year 2011	(1,291,157)	41,830	662,392	(1,998,139)	(1,335,747)	-	**(2,585,074)**	(2,585,074)	(0)	
Year 2012 to June 30, 2012	(2,585,074)	28,679	(929,556)	5,801,100	4,871,544	1,316,166	3,631,315	3,631,315	0	*Note 2.*
Year-to-date		**76,230**	**2,258,788**	**-**	**2,258,788**	**(685,733)**				

Note 1: Disposition set out in the Board's Decision in London Hydro's 2009 COS Application (EB-2008-0235) for the period of Oct 1, 2009 to April 30, 2011.
Note 2: Disposition set out in the Board's Decision in London Hydro's 2012 IRM Application (EB-2011-0181) for the period of May 1, 2012 to April 30, 2014.

1588 RSVA Power Sub-account Global Adjustment recalculated with eliminating the amount for fixed price credit accrued in error after the accrual method is implemented

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Credits	Total Net Accruals	Board Approved Disposition	Closing Balance
No fixed price credit accrued in Year 2008				-	-		
Year 2009	1,982,029	8,365	5,408,166	(4,262,161)	1,146,005	(2,001,899)	1,134,500
Year 2010	1,134,500	(2,644)	(2,882,212)	4,262,161	1,379,948	-	**2,511,804**
Year 2011	2,511,804	41,830	662,392	-	662,392	-	**3,216,026**
Year 2012 to June 30, 2012	3,216,026	28,679	(929,556)	-	(929,556)	1,316,166	3,631,315
Year-to-date		**76,230**	**2,258,788**	**-**	**2,258,788**	**(685,733)**	

The above tables illustrate after the last reversal of the fixed price debits/credits in 2012, the closing balance of the account is the same as if the fixed price debits/credits were accrued only for the time period the forward methodology was employed.

The total transactions, including carrying charges on paid/billed principal, are the same for over the years.

c) London Hydro can confirm the 1588 RSVA Power account had the correct balances for each year, and therefore the appropriate balances were approved for disposition.

The external audit conducted by the Ministry of Finance on the behalf of the Ontario Power Authority, confirmed the 1588 RSVA Power and 1588 Power Sub-account Global Adjustment balances as at 2008.

In regards to the 1588 Power Sub-account Global Adjustment there had been no additional accruals made for fixed price credits on unbilled energy in 2008. The appropriate accrual entry was added during the 2009 year . However, the accrual entry was no longer required upon implementation of the accrual method in year 2010.

London Hydro is unable to acquire extensive historical information prior to 2008 within the short period of time associated with this submission. However, London Hydro is confident that the account balance for 1588 Power Sub-account Global Adjustment for Year 2011 is now correct. By disposing the current recalculated balance any prior error resulting from incorrect accruals or disposition is self-corrected.

Question OEB 52

Reference: EB-2012-0380 pre-filed evidence filed September 25, 2012 / p. 6.

London Hydro stated at the referenced page that it had performed an internal review of the unbilled energy calculation and discovered that the fixed price debits/credits were calculated and included twice in the unbilled energy period end balance.

a) *Please file with the Board a copy of the London Hydro's internal review and analysis, if any, with respect to this issue.*
b) *When London Hydro refers to the fixed price debits/credits and unbilled energy does it mean an inaccurate unbilled RPP kWh accrual at period-end and*

subsequent reversal the following period? Please explain if this is the case or not. Please explain what was accrued at period-end and what was or was not reversed the following period.

c) *When London Hydro refers to the fixed price debits/credits and unbilled energy does it mean that the inaccurate RPP kWh accrual caused an inaccurate impact to the following calculation for Form 1598 and its predecessor forms (e.g. Form 1506, etc.)? Please explain if this is the case or not..*

d) *Please also confirm that London Hydro uses the formula*
*"Fixed price adjustment = RPP kWh * [$RPP/kWh - ($HOEP/kWh + $Global Adjustment/kWh)"*
in its calculation for Form 1598 and its predecessor forms (e.g. Form 1506, etc.). Please explain if this is the case or not the case.

e) *Please explain and provide a schedule to show how the inaccurate unbilled RPP kWh accrual and other inaccurate adjustments to the above "Fixed price adjustment" calculation were incorporated into each year-end balance – the period-ends since the inception of Form 1598 and its predecessor forms (e.g. Form 1506, etc.), not just since year-end 2008. Please detail by each year-end. Please reconcile this schedule to the schedules detailed in Appendix A of the pre-filed evidence filed on September 25, 2012 page 15 and page 16.*

Response OEB 52

a) Please refer to Appendix D – RSVA Commodity Variance Accounts – Unbilled Energy Calculation Review 1588 RSVA Power and RSVA Power Sub-account Global Adjustment ("RSVA background document")

b) The fixed price adjustments on unbilled energy were calculated and using the appropriate applicable rates.

The accrual is required for the unbilled portion of the RPP price variance due to the IESO and is calculated and accrued at the end of each month.

This entry reverses on the first day of the next month. Then a new reversing accrual is booked for the required amount at the end of the month again.

The accrual was not required for the unbilled portion of global adjustment fixed price credits because the accrual method is used in the calculation for the submission. This entry reversed on the first of the next month. After the initial review of the unbilled energy calculation, no further accruals were booked.

Further details are provided in RSVA background document.

c) The RPP settlement amount for Form 1598 is calculated using the applicable formula. This amount is submitted to the IESO and included in the IESO invoice as Charge Type 142. The invoice for the trade month is received from IESO around the 10th business day in the following month. All charges including 1598 settlement amount, are booked as unbilled cost of power for the month of consumption based on the invoice received from the IESO.

The accruals booked to the ledger have no impact on the calculation of amounts submitted on the Form 1598.

The accrual is a second adjustment booked for the fixed price debits/credits in addition what is already settled with the IESO. This calculation takes place after the Form 1598 is submitted. The accrual for the global adjustment credit should not have been made as described in the RSVA background document.

d) Yes, London Hydro uses the above described formulae to calculate the RPP adjustment amount (Charge Type 142) to be settled with the IESO.

The amount calculated for the Global adjustment (RPP kWh * $GA/kWh) uses the accrual method described in the APH, and all estimates are trued up two months later when actual billed amounts become available.

The amount calculated for the energy price adjustment (RPP kWh * ($RPP/kWh – $HOEP/kWh) uses the forward method where the settlement amount for the price differences are based on current month billings. The current month billings include billings for consumption of the current month and the prior month. The RPP price difference for the unbilled portion of consumption is submitted in the following month, therefore an accrual is required in the current trade month as described in RSVA background document.

e) London Hydro can confirm that 1588 RSVA Power account has no error; therefore there is no change necessary to balances prior to Year 2012. The IESO settlement has been completed on a forward basis for the RPP energy price difference since the inception of Form 1598, and therefore the accrual entry for the unbilled portion of the RPP fixed price difference is required to arrive at the same month-end results as the accrual method. The accrual entry accounts for this outstanding amount and moves it to Accounts Payable due to the IESO. This entry should be completed as long as the forward method is in place for the calculation of the fixed price debits. The existing rate rider is not affected.

Recordings for Global Adjustment were introduced in Year 2005. The forward method was used in calculation of the RPP price differences prior August 2010. Therefore the accrual entry was required to arrive at the

same results as the accrual method. The additional accrual entry made for fixed price credits on unbilled energy in 1588 Power Sub-account GA was implemented in Year 2009.

The accrual method was adopted in 2010 and therefore the accrual entry was not necessary after August 2010. The result was 1588 Power Sub-account Global Adjustment reflected a double accrual commencing in August 2010.

The reversing accrual entry at end of December 2010 and 2011 was made for $3.8 Million and $5.8 Million, respectively, for the RPP related Global Adjustment credit. Please review response OEB IR 54 a) and the table reflecting the correction of the amount $5.8 Million that adjusts the 1588 Power Sub-account GA December 31, 2011, balance for proposed recovery.

Further reference can be found in response to question OEB 52a) in the RSVA background document.

1588 RSVA Power (excluding Global Adjustment) as filed and reconciled to RRR 2.1.7

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Debits	Total Net Accruals	Board Approved Disposition	Closing Balance	RRR 2.1.7	Variance	
2008 Year-end accrual for Fixed Price Credit reversing in 2009				1,187,000	1,187,000					
Year 2009	(3,015,389)	(66,735)	(3,908,474)	2,269,300	(1,639,174)	3,040,110	(1,681,188)	(1,681,188)	(0)	*Note 1.*
Year 2010	(1,681,188)	(44,119)	(390,197)	349,800	(40,397)	-	(1,765,703)	(1,765,703)	0	
Year 2011	(1,765,703)	(111,746)	(4,479,632)	2,266,500	(2,213,132)	-	(4,090,581)	(4,090,581)	(0)	
Year 2012 to June 30, 2012	(4,090,581)	(76,062)	(833,576)	(6,072,600)	(6,906,176)	1,784,283	**(9,288,536)**	(9,288,536)	(0)	*Note 2.*
		(298,661)	**(9,611,879)**	**-**	**(9,611,879)**	**4,824,393**				

Note 1: Disposition set out in the Board's Decision in London Hydro's 2009 COS Application (EB-2008-0235) for the period of Oct 1, 2009 to April 30, 2011.
Note 2: Disposition set out in the Board's Decision in London Hydro's 2012 IRM Application (EB-2011-0181) for the period of May 1, 2012 to April 30, 2014.

1588 RSVA Power (excluding Global Adjustment) recalculated with the amount for fixed price debit due to the IESO

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Debits	Total Net Accruals	Board Approved Disposition	Closing Balance
2008 Year-end accrual for Fixed Price Credit reversing in 2009				1,187,000	1,187,000		
Year 2009	(3,015,389)	(66,735)	(3,908,474)	2,269,300	(1,639,174)	3,040,110	(1,681,188)
Year 2010	(1,681,188)	(44,119)	(390,197)	349,800	(40,397)	-	(1,765,703)
Year 2011	(1,765,703)	(111,746)	(4,479,632)	2,266,500	(2,213,132)	-	(4,090,581)
Year 2012 to June 30, 2012	(4,090,581)	(76,062)	(833,576)	909,300	75,724	1,784,283	**(2,306,636)**
		(298,661)	**(9,611,879)**	**6,981,900**	**(2,629,979)**	**4,824,393**	

The above table illustrates the fixed price debits for the unbilled portion of energy price differences due to the IESO using the fow ard method. The entry for the "fixed price debits" is the value of this outstanding liability. This liability is allocated to 2205 Accounts Payable Due to the IESO account from 1588 RSVA Pow er.

1 The total actual paid/invoiced transactions, including carrying charges on paid/billed principal, are the same for over the years.

1

1588 RSVA Power Sub-account Global Adjustment

* as Filed RRR 2.17

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Credits	Total Net Accruals	Board Approved Disposition	Closing Balance	RRR 2.1.7	Variance	
No fixed price credit accrued in Year 2008				-	-					
Year 2009	1,982,029	8,365	5,408,166	(4,262,161)	1,146,005	(2,001,899)	1,134,500	1,134,500	0	*Note 1.*
Year 2010	1,134,500	(2,644)	(2,882,212)	459,200	(2,423,013)	-	**(1,291,157)**	(1,291,157)	0	
Year 2011	(1,291,157)	41,830	662,392	(1,998,139)	(1,335,747)	-	**(2,585,074)**	(2,585,074)	(0)	
Year 2012 to June 30, 2012	(2,585,074)	28,679	(929,556)	5,801,100	4,871,544	1,316,166	3,631,315	3,631,315	0	*Note 2.*
Year-to-date		**76,230**	**2,258,788**	**-**	**2,258,788**	**(685,733)**				

Note 1: Disposition set out in the Board's Decision in London Hydro's 2009 COS Application (EB-2008-0235) for the period of Oct 1, 2009 to April 30, 2011.
Note 2: Disposition set out in the Board's Decision in London Hydro's 2012 IRM Application (EB-2011-0181) for the period of May 1, 2012 to April 30, 2014.

1588 RSVA Power Sub-account Global Adjustment recalculated with eliminating the amount for fixed price credit accrued in error after the accrual method is implemented

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Credits	Total Net Accruals	Board Approved Disposition	Closing Balance
No fixed price credit accrued in Year 2008				-	-		
Year 2009	1,982,029	8,365	5,408,166	(4,262,161)	1,146,005	(2,001,899)	1,134,500
Year 2010	1,134,500	(2,644)	(2,882,212)	4,262,161	1,379,948	-	**2,511,804**
Year 2011	2,511,804	41,830	662,392	-	662,392	-	**3,216,026**
Year 2012 to June 30, 2012	3,216,026	28,679	(929,556)	-	(929,556)	1,316,166	3,631,315
Year-to-date		**76,230**	**2,258,788**	**-**	**2,258,788**	**(685,733)**	

The above tables illustrate after the last reversal of the fixed price debits/credits in 2012, the closing balance of the account is the same as if the fixed price debits/credits were accrued only for the time period the forward methodology was employed.
The total transactions, including carrying charges on paid/billed principal, are the same for over the years.

2

Question OEB 53

Reference: EB-2012-0380 pre-filed evidence filed September 25, 2012 / p. 15.

In Appendix A of the pre-filed evidence page 15, London Hydro has shown an impact on the 2008 year-end accrual in the first table regarding the control account of Account 1588, but it has not shown any impact for the year-end accrual in the second table. In the same appendix on page 16, the Account 1588 sub-account GA/Account 1589 GA reconciliation does not show a 2008 year-end accrual and instead it starts with the 2009 year-end.

a) Please explain why the schedules shown on page 15 start with the year 2008 in the first table of the schedule and the year 2009 in the second table of the schedule.

b) Please explain why the schedules shown on page 16 start with the year 2009 and not the year 2008.

Response OEB 53

Please reference the RSVA background document found in Appendix D and identified in Board staff Q3 52 before reading the response to this question.

a) Based on the findings contained in the RSVA background document referenced in Q# 52 and Appendix D, these tables are no longer relevant.

b) In Appendix D of the Power Variance Account Application the first table illustrates the 1588 RSVA Power Sub-account Global Adjustment with the accrual made for fixed price debits. The second table illustrates the variance account without the accrual to show what the end balance would have been if the entry was never made.

There was no entry made for Global Adjustment fixed price credit at the end of Year 2008. Please note that the opening balance is identical in both the first and second tables - $1.98 Million. This is because there was no accrual made in Year 2008, so both tables have the same opening balance without the extra accrual.

Question OEB 54

References:

i. *Application for Disposition of RSVA Group 1 Accounts, (pre-filed evidence in EB-2012-0380), pp. 12-13 and 21-23.*

ii. *Exhibit 9, pap. 46 - 47*

a) *Please provide the principal balances as of December 31, 2011 for all deferral and variance accounts including Account 1588 RSVA Power (excluding the Global Adjustment) and Account 1588 RSVA Power Global Adjustment sub-account. The balances in Account 1588 RSVA Power (excluding the Global Adjustment) and Account 1588 RSVA Power Global Adjustment sub-account should reflect the corrections required to redress the alleged error of $3.8 million.*

b) *Please calculate the rate riders applicable to RPP and non-RPP customers as per part a) of this interrogatory, assuming an implementation date of February 1, 2013. Please include carrying charges up to January 31, 2013 and assume a sunset date of April 30, 2014.*

c) *Please calculate the rate riders applicable to RPP and non-RPP customers as per part a) of this interrogatory, assuming an implementation date of May 1, 2013. Please include carrying charges up to April 30, 2013, and assume a sunset date of April 30, 2014.*

Response OEB 54

a)

Table 9-3 – Deferral and Variance Accounts Submitted for Recovery with this Application Updated

Accounts for Which Disposition is Requested in This Application - Updated to include 1588 RSVA Power accounts	Net Accruals / Variances	Carrying Charges	Ending Balances at Dec. 31, 2011	Recoveries / Adjustments to April 30,2013	Amount Approved for Disposition May 1, 2012	Projected Interest Jan 12 to Apr 30/13 - 1.47%	Projected Balances as at Apr 30/13
Group 1 Accounts:							
1580 RSVA - Wholesale Market Service Charge	$ (8,261,909)	$ (115,645)	$ (8,377,554)		$ 4,469,082	$ (84,464)	$ (3,992,936)
1584 RSVA - Retail Transmission Network Charge	774,015	11,977	785,992		(544,497)	8,689	250,184
1586 RSVA - Retail Transmission Connection Charge	(279,774)	(17,419)	(297,193)		617,705	4,900	325,412
1588 RSVA - Power (excluding Global Adjustment)	(3,896,805)	(193,776)	(4,090,581)		1,784,283	(57,600)	(2,363,898)
1588 RSVA - Power - Sub-account - Global Adjustment	(2,612,754)	27,680	(2,585,074)	5,801,100	1,316,166	87,201	4,619,393
1595 Disposition and Recovery/Refund of Regulatory Balances (2009)	-	(286,860)	(286,860)			-	(286,860)
Group 2 Accounts:							-
1508 Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	349,024	6,649	355,673			6,817	362,490
1518 Retail Cost Variance Account - Retail	(82,253)	(1,531)	(83,784)			(1,607)	(85,391)
1548 Retail Cost Variance Account - STR	86,736	1,488	88,224			1,694	89,918
1592 PILs and Tax Variance for 2006 and Subsequent Years	(130,133)	(16,514)	(146,647)			(2,542)	(149,189)
1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	(185,546)	(1,852)	(187,398)			(3,624)	(191,022)
	$ (14,239,399)	**$ (585,803)**	**$ (14,825,202)**	**$ 5,801,100**	**$ 7,642,739**	**$ (40,536)**	**$ (1,421,899)**
1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	3,550,757	-	3,550,757	(396,675)		-	3,154,082

The above table includes the correction of $5.8 Million to the 1588 RSVA Power Sub-account Global Adjustment.

b) The proposed recalculated rate riders are based on the December 31, 2011 audited 1588 RSVA Power and 1588 RSVA Power Sub-account Global Adjustment updated balances and applicable carrying charges to January 31, 2013, with assumed implementation date of February 1, 2013 and sunset date of April 30, 2014.

Exhibit 9 - Table 4 - Proposed Updated Rate Rider for Deferral / Variance Account Balances (excluding Global Adjustment)

Rate Class	Billing Parameter	Proposed Rate - Feb 1/13 to Apr 30/14
Residential	kWh	$ (0.0006)
GS <50 kW	kWh	$ (0.0006)
GS 50 to 4,999 kW	kW	$ (0.2277)
GS 50 to 4,999 kW (Co-Generation)	kW	$ (0.1174)
Standby	kW	$ (0.1174)
Large Use >5MW	kW	$ (0.2873)
Street Light	kW	$ (0.2028)
Sentinel	kW	$ (0.2087)
Unmetered Scattered Load	kWh	$ (0.0006)

Exhibit 9 - Table 5 - Proposed Updated Rate Rider for RSVA - Global Adjustment Account

Rate Class	Billing Parameter	Proposed Rate - Feb 1/13 to Apr 30/14
Residential	kWh	$ 0.0025
GS <50 kW	kWh	$ 0.0025
GS 50 to 4,999 kW	kW	$ 1.0026
GS 50 to 4,999 kW (Co-Generation)	kW	$ 0.5170
Standby	kW	$ 0.5170
Large Use >5MW	kW	$ 1.2652
Street Light	kW	$ 0.8931
Sentinel	kW	$ 0.9189
Unmetered Scattered Load	kWh	$ 0.0025

c) The proposed recalculated rate riders are based on the December 31, 2011 audited Deferral / Variance Account balances (including the updated 1588 RSVA Power Account and Power sub-account RSVA Global Adjustment),and applicable carrying charges to April 30, 2013, as presented in ***Table 9-3 – Deferral and Variance Accounts Submitted for Recovery with this Application Updated*** within response to Question 54 in Part a).

Rate Class	Billing Parameter	Proposed Rate - May 1/13 to Apr 30/14
Residential	kWh	$ (0.0018)
GS <50 kW	kWh	$ (0.0018)
GS 50 to 4,999 kW	kW	$ (0.7312)
GS 50 to 4,999 kW (Co-Generation)	kW	$ (0.3770)
Standby	kW	$ (0.3770)
Large Use >5MW	kW	$ (0.9227)
Street Light	kW	$ (0.6389)
Sentinel	kW	$ (0.6625)
Unmetered Scattered Load	kWh	$ (0.0018)

Exhibit 9 - Table 5 - Proposed Updated Rate Rider for RSVA - Global Adjustment Account

Rate Class	Billing Parameter	Proposed Rate - May 1/13 to Apr 30/14
Residential	kWh	$ 0.0025
GS <50 kW	kWh	$ 0.0025
GS 50 to 4,999 kW	kW	$ 1.0026
GS 50 to 4,999 kW (Co-Generation)	kW	$ 0.5170
Standby	kW	$ 0.5170
Large Use >5MW	kW	$ 1.2652
Street Light	kW	$ 0.8931
Sentinel	kW	$ 0.9189
Unmetered Scattered Load	kWh	$ 0.0025

Stranded Meter costs

Question OEB 55

References:

i. Exh 9, p. 15: Table 9-3;

ii. Exh 9, p. 19: Table 9-5

iii. DVA Continuity Schedule Work Form;

Table 9-3 lists all the DVA balances London Hydro is requesting for disposition. Currently Table 9-3 shows a total credit balance of $523,313. However, Table 9-3

includes the balance of $3,154,081 for Account 1555, Smart Meter Capital & Recovery Offset Variance-Sub account, Stranded Meter Costs.

It is to be noted that a separate rate rider was proposed in Table 9-8 for Account 1555, sub account Stranded Meters.

a) *Please confirm that London Hydro is requesting disposition of account 1555, Smart Meter Capital & Recovery Offset Variance-Sub account, Stranded Meter Costs through a separate rate rider, Stranded Meter Rate Rider (SMRR).*

b) *Please confirm that the total DVA balance requested for disposition in Table 9-3 is a credit balance of $3,677,394 balance (excluding sub account Stranded Meter Costs) and that the DVA rate riders in Table 9-5 calculation were based on the $3,677,394 credit balance (and not on $523,313 credit balance which includes the subaccount).*

Response OEB 55

a) Yes, London Hydro is requesting the disposition of account 1555 Smart Meter Capital and Recovery Offset Variance – Sub-Account, Stranded Meter Costs through a separate rate rider, Stranded Meter Rate Rider (SMRR). The total amount of Stranded Meter Costs requested for disposition is $3,154,081. *Ref. Exh. 9 pages 21 and 22, Tables 9-6 and 9-7.* The proposed class specific rate riders are set out in Table 9-8 - Proposed Stranded Asset Recoveries Rate Rider in Exhibit 9 Page 22. The rate riders would apply with an effective date of May 1, 2013 and are based on a 12-month disposition period.

Table 9-8 – Proposed Stranded Asset Recoveries Rate Rider

Rate Class	Billing Parameter	Proposed Rate - May 1/13 to Apr 30/14
Residential	Monthly	$ 1.58
GS <50 kW	Monthly	$ 3.77

b) London Hydro confirms that Table 9-3 includes all DVA accounts that London Hydro requested disposition of in its 2013 COS Rate Application. Of these balances, disposition of account 1555 Smart Meter Capital and Recovery Offset Variance – Sub-Account, Stranded Meter Costs is requested through a separate rate rider, Stranded Meter Rate Rider (SMRR). Table 9-3 is now updated with the 1588 RSVA Power and sub-account Global Adjustment accounts requested for disposition. The total of all the other DVA accounts (excluding sub account Stranded Meter Costs), is a $1,421,899 credit balance, which is reflected in the updated EDDVAR Continuity Schedule. The amount consists of the December 31, 2011 balances plus the OEB prescribed interest projected to April 30, 2013. The disposition of this $1,421,899 credit balance is requested through the proposed updated rate riders set out in Table 9-5 in response to question 54 part c. These rate riders were calculated utilizing the EDDVAR Continuity Schedule for 2013 COS Filers.

Treatment of Recordings to MIFRS from CGAAP (Exhibit 10)

MIFRS Opening Net Book Value

Question OEB 56

References:

i. Appendix 2-B, December 31, 2012 MIFRS;
ii. Appendix 2-CG, Depreciation & Amortization Expense, MIFRS 2012

Under MIFRS, the ending net book value of $205,596,724 ($386,546,051 less $180,949,327) as of December 31, 2011 for the Plant & Property Equipment (PP&E) in Appendix 2-B differs from the net book value as of January 1, 2012 of $215,885,605 for the PP&E in Appendix- CG by $10,288,881.

a) Please account for and explain the difference of $10,288,881.

b) Did London Hydro exclude the assets still on the books but which have been fully amortized or depreciated as per Note 5 in Appendix 2-CG?

c) If the answer is yes to part "b", please state the $ amount.

d) Please state which is the correct January 1, 2012 beginning balance under MIFRS for Appendix 2-B and Appendix 2-CG.

Response OEB 56

a) The difference of $10,288,881 between the opening net book value of capital assets at January 1, 2012 as presented in OEB Appendix 2-B and OEB Appendix 2-CG is associated with the presentation of work-in-progress, renewable generation assets and smart meters as displayed below:

	Cost	Accumulated Amortization	Net Book Value
MIFRS, NBV January 1, 2012 per 2012 continuity schedule (OEB Appendix 2-B)	386,546,051	(180,949,327)	205,596,724
Differences between OEB Appendix 2-B and 2-CG			
Work-in-progress	(10,617,840)		(10,617,840)
Renewable generation assets	(935,237)	31,821	(903,416)
Smart meter assets transferred from OEB deferral account 1555	24,403,497	(2,593,363)	21,810,134
Rounding			3
	12,850,420	(2,561,542)	**10,288,881**
MIFRS, NBV January 1, 2012 per OEB Appendix 2-CG	399,396,471	(183,510,869)	215,885,605

b) Amounts provided in column (a) of OEB Appendix 2-CG for the MIFRS opening net book value as at January 1, 2012 represent the net book value of capital assets under CGAAP at January 1, 2012. Fully depreciated assets under CGAAP are excluded since such items would inherently have a net book value of nil.

These CGAAP balances at January 1, 2012 listed under column (a) do include those assets that had a net book value at January 1, 2012 under CGAAP, but which had no remaining life once the new adopted MIFRS life spans were applied effective January 1, 2012. As addressed in Exhibit 10, the CGAAP net book value of assets with no remaining life under new MIFRS life spans amounted to $4,745,148.

CGAAP net book value at January 1, 2012 has been provided in column (a) to assist in providing a trail between CGAAP to MIFRS and a better tie to asset continuity schedules. The impact of the increase to 2012 depreciation expense as a result of the assets with no remaining life being expensed under MIFRS ($4,745,148) is captured under column (k) which lists 2012 depreciation expense.

c) Not applicable.

d) Both OEB Appendix 2-B and 2-CG report the opening net book value of capital assets under CGAAP. Any differences relate to the presentation of work-in-progress, renewable generation assets and smart meters as noted above. Accordingly, both schedules are correct.

MIFRS Treatment of Asset Impairment

Question OEB 57

References:
i. Exh 10: Appendix 10 B, page 5;
ii. EB 2008-0408 Report of the Board, Transition to IFRS, page 20, S. 6

In the Report of the Board, Transition to IFRS, the Board stated:

> *"Treatment of asset impairment*
>
> *Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates."*

London Hydro stated in its capitalization policy:
> *"Where the amount by which the asset's carrying amount or net book value exceeds its recoverable amount, the impairment loss is recognized in profit or loss."*

a) Are there any projected asset impairment losses for 2013?

b) Please confirm if London Hydro has asset impairment losses reclassified to PP&E in 2013 in its current COS rate application.

c) Please specify the amount in part a and indicate the type of assets and the rationale for the projected asset impairment loss?

d) Please state London Hydro's proposed accounting treatment for the asset impairment of loss under MIFRS.

e) Is London Hydro's capitalization policy on impairment loss following the Board's guidelines for 2013? If not, please explain.

Response OEB 57

a) There is no asset impairment losses projected for 2013. To clarify, no amount has been included in the 2013 COS rate application under Rate Base, OM&A or Depreciation.

b) London Hydro confirms that there are no asset impairment losses reclassified to PP&E.

c) Not applicable.

d) Not applicable.

e) London Hydro's capitalization policy as referenced under Exhibit 10, Appendix 10B pertains to external reporting under IFRS. This policy does not discuss reporting under MIFRS in accordance with Board's guidelines for 2013.

When London Hydro does encounter an asset impairment loss, and when reporting the same under MIFRS for rate making purposes, London Hydro will follow Board guidelines applicable at that time.

MIFRS Pension and Other Post-Employment Benefits

Question OEB 58

References

i. Exh 10, page 21 Pension & Other Post-Employment Benefits;
ii. Addendum to Report of the Board: Implementing International Financial Reporting Standards (IFRS) in an Incentive Rate Mechanism Environment dated June 13, 2011 (EB 2008-0408), pp. 23- 24

London Hydro's IFRS transitional adjustment for Pension and Other Post-Employment Benefits ("P&OPEB") is $1,844,800, representing the difference in the Company's liability under IFRS in comparison to that calculated under CGAAP as at January 1, 2012. The transitional adjustment represents unamortized actuarial losses and an unrecognized liability associated with future benefits relating to service awards, which is not a requirement under CGAAP but is a new requirement under IFRS.

This transitional adjustment has no impact on revenue requirement as filed in this Application and no carrying charges have been applied to this amount. Since IFRS has not yet been fully implemented, this transitional adjustment is being made as a place holder only until such time as transition to IFRS has been completed.

a) *Please confirm that London Hydro is asking for a deferral and variance account per Addendum to Report of the Board: Implementing International Financial Reporting Standards (IFRS) in an Incentive Rate Mechanism Environment dated June 13, 2011 (EB 2008-0408), pp. 23- 24.*

b) What is London Hydro's proposed accounting treatment for P&OEB transitional adjustment when the transition to IFRS has been completed?

Response OEB 58

a) London Hydro confirms that it is asking for a deferral and variance account as per the Addendum to EB 2008-0408 dated June 13, 2011, pp. 23-24 which states that "Individual utilities that can demonstrate the likelihood of large variances can seek an individual variance account from the Board."

As mentioned in the COS rate application and above, although London Hydro has not yet transitioned to IFRS, this deferral account is being requested as a place holder for its forthcoming transitional P&OPEB adjustment which will be made when transition to IFRS is in fact complete.

b) The Company has chosen to defer IFRS implementation to the new mandated transition date of January 1, 2014. In view of the foregoing, London Hydro has not yet developed a proposed accounting treatment associated with the P&OPEB adjustment for rate-setting purposes.

Once London Hydro has transitioned to IFRS and has made this P&OPEB adjustment to the opening balance sheet, it will provide a proposed accounting treatment that is consistent with that used by LDC's as the industry standard at that time.

Account 1592 PILS & Tax Variance for 2006 and Subsequent Years

Question OEB 59

References:
i. Exh 9, Page 5, Table 9-3;
ii. Appendix 2-T,
iii. APH FAQs, July 2007, #1- #5

London Hydro is requesting for disposition of Account 1592, 'PILS & Tax Variance for 2006 and Subsequent Years' (excludes sub accounts and contra accounts), for a credit balance of $149,189 in Table 9-3.

Note 3 of Appendix 2-T requires the calculations that show how each item was determined and any supporting evidence and documentation. In addition, Note 4 of Appendix 2-T must state whether or not the applicant followed the guidance provided in the FAQs of 2007.

a) Please provide the calculations of each item and the supporting evidence and documentation required in Appendix 2-T

b) Please confirm that London Hydro followed the FAQs of 2007. If not, please explain.

Response OEB 59

a) Contained in updated Appendix 2-T (Appendix 2-T Def Tax_2013_01_08) reflects the evidence and calculations that determined the Account 1592, PILS & Tax Variance for 2006 and Subsequent Years.

Referencing the Appendix 2-T on tab 2- PILS Calculations, is a copy of the 2006 EDR filing for London Hydro's Ontario Capital Tax, Large Corporation Tax. The filing utilizes the OEB 2006 PILs form. In its Decision (RP-2005-0020 and EB-2005-0389) the Board approved this form and to include $130,143 for Grossed-up LCT (cell E38 of this tab).

Again referencing the Appendix 2-T, referring to tab 5- Carry FW is a spreadsheet permitting the recording of the monthly LTC Credit of the approved Grossed-up PILS of $130,143. Referring to cell B 50 of the Appendix 2-T under column D is the monthly LTC Credit ($130,143/ 12 = $18,844 monthly) as collected from customer from period May 1, 2006 through to April 30, 2007. This represents an entire year of credited grossed-up LCT.

Also reflected in Tab 5 is use of applicable OEB prescribe interest rates and LTC credit balances to calculate the relevant carrying charges owed to our customers through period up to April 30, 2013. The amount of

$130,143 and carrying charges to April 30, 2013 of $19.046, totals the amount of disposition requested in the Application, an amount of $149,189.

b) London Hydro confirms that it followed the FAQs of 2007 (APH FAQ, July 2007, #1-#5) in determining the balances of Account 1592, 'PILS & Tax Variance for 2006 and Subsequent Years'.

Account 1592 for HST Savings

Question OEB 60

References:

i. Exh 9, Page 5, Table 9-3;
ii. DVA Continuity Schedules Work Form;
iii. Exh 9, Page 13: Table: HST Savings Liability for July 2010 to December 31, 2011;
iv. Appendix 2-T;
v. 2013 Cost of Service Filing Requirements for Electricity Transmission and Distribution Applications, sections 2.12.1 and 2;
vi. APH FAQ #4, December 2010

London Hydro is requesting for disposition of Account 1592, 'PILS & Tax Variance for 2006 and Subsequent Years, sub account HST/OVAT/ITCs', for a credit balance of $191,022 in Table 9-3 for Account 1592, 'PILS & Tax Variance for 2006 and Subsequent Years, sub account HST/OVAT/ITCs'.

Note 3 of Appendix 2-T requires the calculations show how each item was determined and any supporting evidence and documentation. Appendix 2-T does not show the balance in Account 1592, PILS & Tax Variance for 2006 and Subsequent Years , sub account HST/OVAT/ITCs.

The 2013 COS filing requirements expects that no more amounts should be recorded in the above sub account 1592, HST/OVAT/ITCs for the test year and going forward.

a) *Please confirm that London Hydro is seeking disposition for account 1592, sub account HST/OVAT/ITCs.*

b) Please provide the detailed schedules, similar to Table 1 and Table 2 of Question 4 of the December 2010 APH FAQs, to indicate the period HST savings on OM&A costs and capital expenditures for the periods of:

I. July 1, 2010 to December 31, 2010;
II. January 1, 2011 to December 31, 2011;
III. January 1, 2012 to December 31, 2012; and
IV. January 1, 2012 to December 31, 2013

c) Since the calculation of the HST savings in question 4 of the December 2010 APH FAQs for OMA costs and capital expenditures is based on a proxy using 2009 spending, has the distributor experienced actual spending which were materially different from the above-noted periods in part a? If so please explain the basis for the differences and provide detailed schedules for the HST savings for each period.

d) If the answer in part b is "yes", please update the table found in Exhibit 9, page 13 to reflect part b above, from July 1, 2010 to April 30, 2013 including the related carrying charges.

e) Please update Appendix 2-T to include the balance in Account 1592, sub account HST/OVAT/ITCs.

f) Please confirm that London Hydro will stop recording in sub account 1592, HST/OVAT/ITCs from May 1, 2013 onwards.

Response OEB 60

a) London Hydro confirms that it is seeking disposition for account 1592, sub account HST/OVAT/ITCs with respect to amounts accumulated during the audited years ended December 2010 and December 2011.

b) As requested, Table 1 below has been provided to indicate the HST savings associated with capital expenditures in a fashion similar to that set out in Question 4 of the December 2010 APH FAQs:

Table 1 - PST Savings on Capital Purchases

Pre-HST Purchases with PST Included in Assets

	Asset	Depreciation			
		July-Dec 2010	Jan-Dec 2011	Jan-Dec 2012	Total
2010 Purchases	25,635,800	15,919,000	15,919,000	15,919,000	47,757,000
2011 Purchases	25,635,800		15,919,000	15,919,000	31,838,000
2012 Purchases	25,635,800			15,919,000	15,919,000
Total Depreciation Expense (A)		15,919,000	31,838,000	47,757,000	95,514,000
Post HST Purchases with Input Tax Credit excluded from Assets					
2010 Purchases	25,571,441	15,916,973	15,914,945	15,914,945	47,746,863
2011 Purchases	24,861,196		15,894,600	15,870,200	31,764,800
2012 Purchases	25,635,800			15,891,754	15,891,754
Total Depreciation Expense (B)		15,916,973	31,809,545	47,676,899	95,403,417
Total Capital Items PST Savings (A - B)		**$ 2,027**	**$ 28,455**	**$ 80,101**	**$ 110,583**

Also as requested, Table 2 below has been provided to indicate the HST savings associated with OM&A costs and capital expenditures in a fashion similar to that set out in Question 4 of the December 2010 APH FAQs:

Table 2 - Summary of PST Savings from 2009 Historical Year Analysis

	July-Dec 2010	Jan-Dec 2011	Jan-Dec 2012	Total
2009 Historic Year PST Analysis:				
OM&A Expenses PST Savings	113,537	227,073	227,073	567,683
Capital Items PST Savings (Table 1)	2,027	28,455	80,101	110,583
Total Annual PST Savings	115,564	255,528	307,174	678,266
Monthly PST Savings	$ 19,261	$21,294	$25,598	$22,609

Please note that since 2013 is London Hydro's year for rebasing, there is no PST savings associated with the period January 1, 2013 to December 31, 2013.

c) Answer 4 of the December 2010 APH FAQs discusses the options available for calculating the PST savings post July 1, 2010 and indicates that:

"Any alternative method to determine and record incremental ITCs must yield similar results so that there is no material difference between results from the alternative method and the amounts that would be derived from a transactional analysis. The Board established the deferral account to facilitate capturing the savings derived from the implementation of the HST so they can be passed to the distributor's customers in due course.

An alternative method suggested below provides a simplified approach that should also provide administrative cost saving opportunities. This alternative method requires a distributor to complete a detailed one-time analysis of its most recent historic year (prior to implementation of HST). This analysis of the 2009 historic year (i.e., first complete year prior to implementation of the HST) would identify the PST included in OM&A costs and capital spending that would be removed by the elimination of the PST and would be eligible to receive incremental ITCs effective July 1, 2010 under the Excise Tax Act."

In order to save administrative costs, London Hydro chose to follow the simplified approach provided in answer 4 of the December 2010 APH FAQs in that a detailed one-time analysis was performed using 2009 actual transactional data. This analysis served to identify the amount of PST embedded in 2009 spending so as to provide a basis on which to extrapolate the implicit annual PST savings from July 1, 2010 to December 31, 2012.

This analysis was compiled using actual transactions for 2009 and not based on any projections or proxy. Accordingly, there are no differences between actual spending and the basis on which the HST liability was derived.

d) Not applicable.

e) As requested, Appendix 2-T, Deferred PILs Account 1592 Balances, has been amended to include the HST savings liability for the period July 1, 2010 to its last

audited year December 31, 2011. Copy of the Appendix has been filed as amended excel spreadsheet.

f) London Hydro confirms that there will be no further entries to sub account 1592, HST/OVAT/ITCs from May 1, 2013 onwards, with the exception of carrying charges.

Reclass to: Deferral and Variance Accounts (Exhibit 9)

Balances for Disposition

Question OEB 61

Reference: Exh 9, p. 44

Account 1595 (2009)has carrying charges of $286,860 (credit to customers), but appears to have no principal balance.

a) *Please describe the transactions and/or journal entries during 2011 that resulted in reducing the principal balance to exactly $0, and that reduced the interest balance from ($530,575) to ($286,860).*

b) *Will there be transactions and/or interest recorded in this account in 2012?*

Response OEB 61

a) Please refer to Table: Account 1595 –Regulatory Asset Recoveries/ Refunds on next page for details as to transactions during 2011.

Transactions recorded in this subaccount during 2011 consists of:
- $1,691,012 principal refunded to customers
- $249,168 interest refunded to customers
- $5,453 interest applied on outstanding principal

The rate rider was in effect for the period of October 1, 2009 to April 30, 2011. London Hydro has followed practice that recoveries will first be applied to principal balance.

b) There were billing adjustments for prior periods to customer accounts in the amount of $1,057 during the first four months of 2012. The prior period adjustments are related to billing period(s) prior to April 30, 2011.

There will be no further transactions or interest recorded in this sub-account.

Table: Account 1595 –Regulatory Asset Recoveries/ Refunds

Account 1595 - Regulatory Asset Recoveries/Refunds	**Total**	**Principal Sept 30, 2009**	**Interest To Sept 30, 2009**	**Interest Earned on Outstanding Principal Balance After Sept 30, 2009**
Balances at December 31, 2010	**$ (2,221,586)**	**$ (1,691,012)**	**$ (490,487)**	**$ (40,088)**
Recoveries/Refunds Jan 1 to Dec 31 , 2011	$ 1,940,180	$ 1,691,012	$ 249,168	
Interest Jan 1 to Dec 31 , 2011	$ (5,453)			$ (5,453)
Balances at December 31, 2011	**$ (286,860)**	**$ 0**	**$ (241,319)**	**$ (45,541)**
Recoveries/Refunds Jan 1 to Dec 31 , 2012 *(prior period billing adjustments)*	$ 1,057		$ 1,055	$ 1
Interest Jan 1 to Dec 31 , 2012	$ -			
Balances at December 31, 2012	**$ (285,803)**	**$ 0**	**$ (240,264)**	**$ (45,539)**

Treatment of Recordings to MIFRS from CGAAP (Exhibit 10)

IFRS-CGAAP Transitional PP&E Amounts Appendix 2-EB

Question OEB 62

References:

i. *Appendix 2-EB;*
ii. *Appendices 2-B: 2011 CGAAP, 2012 CGAAP and 2012 MIFRS Capital Assets Continuity Schedules;*
iii. *Appendix 2-CF;*
iv. *Exh 5, Table 5-3, p. 7;*
v. *Revenue Requirement Work Form (RRWF):*
   - *Revenue Requirement Tab,*
   - *Cost of Capital (CoC)Tab and*
   - *Rate Base and Working Capital Tab*

In Appendix 2-EB, London Hydro used as the opening net PP&E for both CGAAP & MIFRS, the gross fixed assets as of January 1, 2012 of $386,546,051 instead of the net book value of the regulatory assets of $205,596,723 ($386,546,051 less $180,949,329).

In addition the opening balances of the gross fixed assets under Appendix 2-B ($386,546,051) and Appendix 2-CF ($399,396,471) which are both under CGAAP, are different.

a) *Please explain why London Hydro is using gross fixed assets for PP&E and not the net book value as of January 1, 2012 in Appendix 2-EB?*

b) *Please explain why the opening balances as of January 1, 2012 in Appendix 2-B and Appendix 2-CF are different?*

c) *Which is the correct January 1, 2012 balance for the net fixed assets under CGAAP?*

d) *Should there be any adjustments required, please update all related evidence.*

e) *Appendix 2-EB shows a weighted average cost of capital (WACC) of 11.42% while Table 5-3 and the CoC Tab in the RRWF show a different WACC of 6.86%.Please explain why the WACC in Appendix 2-EB is different from the WACC in the RRWF, Cost of Capital (CoC) Tab and Table 5-3.*

f) *Please state what is the correct WACC (% and $) for London Hydro. Please link the correct WACC to Table 5-3, RRWF- CoC Tab, Revenue Requirement Tab (Return line) and Appendix 2-EB.*

g) If any adjustments are required, please update all evidence (e.g. Appendix 2-EB, Table 5-3, revenue requirement, rate base, depreciation, etc.) impacted by the adjustments.

Response OEB 62

a) An amended Appendix 2-EB has been provided which reports opening PP&E at net book value rather than cost. The original Appendix submitted was inadvertently linked to the cost of PP&E rather than net book value. Please note that this amendment has not changed the calculated closing balance in the deferral account of $471,922.

b) The difference of $12,850,420 between the opening cost of capital assets at January 1, 2012 as presented in OEB Appendix 2-B and OEB Appendix 2-CF is associated with the presentation of work-in-progress, renewable generation assets and smart meters as displayed below:

	Cost	Accumulated Amortization	Net Book Value
CGAAP, NBV January 1, 2012 per 2012 continuity schedule (OEB Appendix 2-B)	386,546,051	(180,949,327)	205,596,724
Differences between OEB Appendix 2-B and 2-CF			
Work-in-progress	(10,617,840)		(10,617,840)
Renewable generation assets	(935,237)	31,821	(903,416)
Smart meter assets transferred from OEB deferral account 1555	24,403,497	(2,593,363)	21,810,134
Rounding			3
	12,850,420	(2,561,542)	10,288,881
CGAAP, NBV January 1, 2012 per OEB Appendix 2-CF	399,396,471	(183,510,869)	215,885,605

c) For rate-making purposes, the correct net fixed assets balance January 1, 2012 under CGAAP is $215,885,605 as displayed above and in Appendix 2-CF. Both OEB Appendix 2-B and 2-CF report the opening net book value of capital assets under CGAAP. Any differences relate to the presentation of work-in-progress, renewable generation assets and smart meters as noted above.

d) Not applicable.

e) The weighted average cost of capital (WACC) provided in the amended Appendix 2-EB has been revised from 11.42% to 6.86% as per Exhibit 5, Table

5-3. The original Appendix submitted inadvertently reported London Hydro's Working Capital Allowance requirement percentage of 11.42%.

f) The correct weighted average cost of capital (WACC) for London Hydro is 6.86% as presented in Exhibit 5, Table 5-3.

g) Appendix 2-EB has been amended to correct the weighted average cost of capital (WACC) from that originally reported (11.42%) to 6.86%. This corrects the amount originally reported for the Adjustment to Return on Rate Base associated with Deferred PP&E from that originally reported of $53,893 to $32,354. Please note that this revision has no impact on the 1575 IFRS-CGAAP Transitional PP&E deferral account or revenue requirement for the 2013 Test Year since Appendix 2-EB was not referenced when calculating revenue requirements as calculated in the RRWF.

MIFRS Presentation Adjustments to RRWF

Question OEB 63

References:

i. Modified IFRS Webinar, Examples 1 & 2 related to PP&E Deferral Account;
ii. Appendix 2-CH;
iii. Revenue Requirement Work Form (RRWF):
- Revenue Requirement Tab,
- Cost of Capital (CoC)Tab and
- Rate Base and Working Capital Tab

In the Modified IFRS Webinar (specifically Examples 1 & 2 related to PP&E Deferral Account) , the total difference in the closing net PP&E, CGAAP vs. MIFRS is split into 2 parts: the amortization portion and the return on rate base. Please refer to the flow of data in Appendix 2-EB to the RRWF, Revenue Requirement Tab and Appendix 2-CH provided in the webinar. The amortization portion of the PP&E is included in the total "Amortization/Depreciation" line and the return on rate base of the of the PP&E is shown under a separate item in the "Return" line in the RRWF, Revenue Requirement Tab. Note that the total amortization/depreciation comes from Appendix 2-CH (test year MIFRS).

Appendix 2-EB showed $117,981 as the amortization and the return on rate base $53,893, a total of $171,874 as the amount included in revenue requirement on rebasing.

In the RRWF: Revenue Requirement Tab filed, London Hydro presented under the line "Return" the amortization of $117,981 and not the return on rate base of $53,983.

For the amortization, London Hydro included $117,981 in the total amortization of $15,906,000 at the bottom of Appendix 2-CH under the column K "2013 Depreciation per Appendix 2-B, Fixed Assets". Note that the $15,906,000 flows through the RRWF, Revenue Requirement Tab under the line "Amortization/Depreciation (Refer to the example in the MIFRS webinar). Currently the total amortization stands at $15,788,219 instead of $15,906,000, a difference of $117,781.

a) *Please explain why London Hydro showed $117,981 (amortization portion) instead of $53,893 (return portion) under the line "Return" in RRWF, Revenue Requirement Tab and did not follow the guidelines in the MIFRS webinar.*

b) *Please confirm that the $117,981 amortization is included in Appendix 2-CH 2013, MIFRS Depreciation & Amortization Expenses.*

c) *Please explain why the total depreciation/amortization line in RRWF-RR Tab of $15,788,219 differs from the total 2013 total depreciation of $15,906,200 found in Appendix 2-CH and Appendix 2-B under 2013 MIFRS.*

d) *If adjustments are required under parts h to j above, please update all related evidence to reflect the correct amounts and appropriate presentation.*

A review of the RRWF, Rate Base Tab showed that the Gross Fixed Assets (Average) line amount is $421,406,711.

e) *Please explain how London Hydro derived $421,406,711.*

f) *Please tie $421,406,711 to Appendix 2-B, 2013 Fixed Assets Continuity Schedule under MIFRS.*

g) *If $421,406,711 amount in the RRWF does not tie with the amount in Appendix 2-B 2013 Fixed Assets Continuity Schedule under MIFRS, please explain.*

h) *What should be the correct amount in the Gross Fixed Assets (Average) line in RRWF, Rate Base and Working Capital Tab.*

i) *If any adjustments are required, please update all related evidence.*

Response OEB 63

a) The RRWF has been amended so that the Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS is provided in the amount of $32,354 as per the amended Appendix 2-EB. The amount originally reported represented the amortization of the IFRS-CGAAP Transitional amount, due to a misunderstanding of the presentation requirements.

b) London Hydro confirms that the amortization of the IFRS-CGAAP Transitional amount over a period of 4 years in the annual amount of $117,981 is included in Appendix 2-CH. This amount has been rounded to $118,000 is reported at the bottom of the Appendix on the line item described as "Depreciation expense from amortization of Account 1575".

c) The RRWF has been amended so that depreciation expense is provided in the amount of $15,906,200, which now corresponds to that provided in Appendix 2-CH and Appendix 2-B. The original amount reported excluded the amortization of the IFRS-CGAAP Transitional amount since this amount was inadvertently reported under the line item for Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS.

d) The RRWF has been amended to present the amortization of the IFRS-CGAAP Transitional amount and Adjustment to Return on Rate Base associated with the Deferred PP&E balance as a result of transition from CGAAP to MIFRS appropriately. In addition, as mentioned above, Appendix 2-EB has been amended so as to report the Adjustment to Return on Rate Base associated with Deferred PP&E balance appropriately as $32,354 rather than $53,893.

e) The RRWF has been amended to present Gross Fixed Assets (average) in the amount of $420,934,789 rather than $421,406,711. The original amount reported included the IFRS-CGAAP Transitional amount in the amount of $471,922. The previous and current presentation is summarized as follows:

MIFRS, Gross Fixed Assets December 31, 2012 (Table 10-4)	413,940,268
MIFRS, Gross Fixed Assets December 31, 2013 (Table 10-4)	427,929,311
	841,869,579
	/2
Average	420,934,789
IFRS-CGAAP Transitional amount	471,922
Gross Fixed Assets (average) as originally reported	421,406,711
Less: IFRS-CGAAP Transitional amount	(471,922)
Gross Fixed Assets (average) per amended RRWF	420,934,789

f) As mentioned above, the original amount reported as Gross Fixed Assets (average) in the RRWF included the IFRS-CGAAP Transitional amount, which has now been corrected. The average of gross fixed assets reported in the RRWF as originally filed and that reported in the amended version provided can be summarized as follows:

	Cost Dec 31, 2012	Cost Dec 31, 2013	Average
MIFRS, Gross Fixed Assets January 1, 2012 per 2012 continuity schedule (OEB Appendix 2-B)	428,343,345	443,392,388	
Differences between OEB Appendix 2-B and RRWF Gross Fixed Assets			
Work-in-progress	(10,617,840)	(10,617,840)	
Renewable generation assets	(3,785,237)	(4,845,237)	
	(14,403,077)	(15,463,077)	
MIFRS, NBV January 1, 2012 per OEB Appendix 2-CG	413,940,268	427,929,311	841,869,579
			/2
			420,934,789
IFRS-CGAAP Transitional amount			471,922
Gross Fixed Assets (average) as originally reported			421,406,711
Less: IFRS-CGAAP Transitional amount			(471,922)
Gross Fixed Assets (average) per amended RRWF			420,934,789

g) Please see the schedule above under item f) which ties Appendix 2-B to Gross Fixed Assets (average) reported in the RRWF.

h) The Gross Fixed Assets (average) line in the RRWF as originally filed should have read $420,934,789. This presentation has now been corrected as noted above.

i) As mentioned above, Appendix 2-EB and the RRWF have been amended.

APPENDIX A – PROJECTS NOT IN SERVICE AS AT DECEMBER 14, 2012

Response to Board Staff IR #9: Green Energy Act Plan)

Appendix A

Projects Not In Service at December 14, 2012

For OEB Response #9 - Green Energy Act Plan

Address	Proponent	Primary Voltage	Transformer Station	Distribution Station	Feeder Designation	Project Size
1275 Hubrey	Bright Power (Jeremy Crane)	27.6kV	Buchanan TS	---	19M22	250kW
30 Adelaide St	Bright Power (Jeremy Crane)	13.8kV	Nelson TS DESN 2	---	13M15	250kW
575 Industrial Road	NEXXSOURCE ENERGY CORP. (Garth Bobb)	27.6kV	Clarke TS	---	70M1	100kW
580 Industrial Road	Sun Edison (Anna Lauritzen)	27.6kV	Clarke TS	---	70M1	250kW
1121 Wellington Road S	RESCo (Michael B. Scott)	27.6kV	Buchanan TS	---	19M37	50kW
1125 WELLINGTON RD. S	RESCo (Michael B. Scott)	27.6kV	Buchanan TS	---	19M37	250kW
1305 Dundas St. E.	RESCo (Michael B. Scott)	27.6kV	Clarke TS	---	70M3	25kW
1875 HYDE PARK ROAD	RESCo (Michael B. Scott)	27.6kV	Talbot TS DESN 2	---	26M54	250kW
1975 DUNDAS ST. E	RESCo (Michael B. Scott)	27.6kV	Clarke TS	---	70M8	250kW
378 HORTON STREET	RESCo (Michael B. Scott)	4.16kV	Nelson TS DESN 1	---	1F2	50kW
15515 Dakota Place	German Solar Corp (Dennis German)		Clarke TS	---		250kW
15701 Robins Hill Road Bldg C	German Solar Corp (Dennis German)	27.6kV	Clarke TS	---	70M1	95kW
15790 Robins Hill Road	German Solar Corp (Dennis German)	27.6kV	Clarke TS	---	70M1	250kW
15825 Robins Hill Road Bldg A	German Solar Corp (Dennis German)	27.6kV	Clarke TS	---	70M1	125kW
15911 Robins Hill Road Bldg G	German Solar Corp (Dennis German)	27.6kV	Clarke TS	---	70M1	250kW
2351 Huron Street Bldg E	German Solar Corp (Dennis German)	27.6kV	Clarke TS	---	70M1	250kW
2391 Huron Street Bldg F	German Solar Corp (Dennis German)	27.6kV	Clarke TS	---	70M1	250kW
865 Florence Street	MMM Group (Nicolas Tyers)	27.6kV	Highbury TS	---	4M13	250kW
217 Sarnia Road	David Kay	27.6kV	Talbot TS DESN 2	---	26M55	153kW
355 Wellington Street	Tenedos Energy (Len Eberhard)	27.6kV	Talbot TS Desn 2	---	26M51	500kW
925 Richmond Street	David Kay	27.6kV	Talbot TS DESN 2	---	26M52	30kW
295 Rectory Street	MMM Group (Nicolas Tyers)	27.6kV	Highbury TS	---	4M13	250kW
535 Sovereign Rd	greenlightPROJECTS INC.(Chris Shilton)	27.6kV	Highbury TS	---	4M11	500kW

1100 Green Valley Rd	Casco	27.6kV	Buchanan TS	---	19M26	500kW
1010 Clarke Side Road	Canada Solar Consortium (Chris Carignan)	27.6kV	Clarke TS	---	70M6	250kW
960 Pond Mills Road	greenlightPROJECTS INC.(Chris Shilton)	27.6kV	Buchanan TS	---	19M27	500kW
3691 Manning Drive	Mann Engineering (John Wong)	27.6kV	Wonderland TS	---	32M1	250kW
745 York Street	TD Bank (Jamie Kruspel)	27.6kV	Highbury TS	---	4M13	250kW
99 Ash Street	Bright Power (Jamie Tremaine)	27.6KV	Highbury TS	---	4M13	250kW
629 Fanshawe Park Rd	Alternate Power International (Medy Merriman)	4.16kV	Talbot TS Desn 1	17	26M11	150kW
164 Albert St	Green Power Promotions (Andrew Hall-Holand)	27.6KV	Talbot TS DESN 1	---	26M22	50kW
98 Clarke Side Road	Tenedos Energy (Len Eberhard)	27.6kV	Highbury TS	---	4M16	500kW
3003 Page Street	Ozz Solar (Richard Di Bon)	27.6kV	Clarke TS	---	70M1	100kW
3537 White Oak Road	Bright Power (Jamie Tremaine)	27.6kV	Buchanan TS	---	19M22	250kW
568 Second Street	Ozz Solar (Richard Di Bon)	27.6kV	Highbury TS	---	4M18	100kW
629 Fanshawe Park Rd	ESEI Power Inc. (Harry Yu)	4.16kV	Talbot TS Desn 1	17	26M11	30kW
2797 Manning Drive	Mann Engineering Ltd.(Michal Jaster)	8.32kV	WONDERLAND TS	97	32M6	100kW
3700 Old Victoria Road	OSP - Ontario Solar Provider (Carlos Rodrigues)	27.6kV	Buchanan TS	---	19M21 HO cct	500kW
242 Pall Mall Street	Ozz Solar (Bobby MacCannell)	27.6kV	Talbot TS Desn 2	---	26M46	100kW
3080 Wonderland Road	Southside Property Mgmt (Peter Moreno)	27.6kV	WONDERLAND TS	---	32M7	250kW
105 Cherryhill Blvd.	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M42	40kW
110 Cherryhill Circle	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	25kW
115 Cherryhill Blvd.	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M42	40kW
120 Cherryhill Place	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	50kW
140 Cherryhill Place	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	45kW
160 Cherryhill Place	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	50kW
170 Cherryhill Circle	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	10kW
180 Cherryhill Circle	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	50kW
190 Cherryhill Circle	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M42	10kW
200 Westfield Drive	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	40kW
201 Westfield Drive	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M42	40kW
230 Platts Lane	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 2	---	26M54	20kW
695 Proudfoot Lane	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 1	---	26M13	150kW
1045 Wonderland Rd. N.	London Hydro /City of London (Allan Van Damme)	27.6kV	Talbot TS Desn 1	---	26M14	186kW
1045 Wonderland Rd. N.	London Hydro /City of London (Allan Van Damme)	27.6kV	Talbot TS Desn 2	---	26M56	87kW

1105 Florence St	London Hydro /City of London (Allan Van Damme)	27.6kV	Buchanan TS	---	19M29	90kW
1153/1165 Adelaide St. N.	London Hydro /City of London (Allan Van Damme)	4.16kV	Talbot TS Desn 1	27F2	26M11	97kW
1221 Sandford Ave	London Hydro /City of London (Allan Van Damme)	4.16kV	Clarke TS	33F1	70M3	227kW
1345 Cheapside St	London Hydro /City of London (Allan Van Damme)	27.6kV	Clarke TS	---	70M7	100kW
20 Granville St.	London Hydro /City of London (Allan Van Damme)	27.6kV	Talbot TS Desn 2	---	26M41	159kW
25 Ridout Street South	London Hydro /City of London (Allan Van Damme)	13.8kV	Nelson TS DESN 2	---	13M15	34kW
275 Boler Rd.	London Hydro /City of London (Allan Van Damme)	4.16kV	Talbot TS Desn 1	25F2	26M13	44kW
370 Chippendale Cres.	London Hydro /City of London (Allan Van Damme)	4.16kV	Buchanan TS	40F1	19M38	107kW
656 Elizabeth St.	London Hydro /City of London (Allan Van Damme)	27.6kV	Talbot TS Desn 2	---	26M53	156kW
663/665 Bathurst St.	London Hydro /City of London (Allan Van Damme)	13.8kV	Nelson TS DESN 2	---	13M15	76kW
675 Grosvenor St.	London Hydro /City of London (Allan Van Damme)	27.6kV	Talbot TS Desn 2	---	26M52	128kW
710 Southdale Rd London	London Hydro /City of London (Allan Van Damme)	27.6kV	Buchanan TS	---	19M24	136kW
7112 Beattie St.	London Hydro /City of London (Allan Van Damme)	27.6kV	WONDERLAND TS	---	32M6	140kW
746 Wellington Rd.	London Hydro /City of London (Allan Van Damme)	4.16kV	WONDERLAND TS	23F3	32M4	41kW
78 Riverside Dr.	London Hydro /City of London (Allan Van Damme)	27.6kV	Talbot TS Desn 1	---	26M25	62kW
799 Homeview Rd.	London Hydro /City of London (Allan Van Damme)	27.6kV	WONDERLAND TS	---	32M4	275kW
824 Dundas St.	London Hydro /City of London (Allan Van Damme)	13.8kV	Nelson TS DESN 2	2K1	13M15	73kW
25 Cuddy Blvd	Glenbarra Energy Management Corp. (John Hamilton)	27.6kV	Clarke TS	---	70M1	200kW
865 Florence Street	Solera Sustainable Energies Company (Jolanda Allen)	27.6kV	Highbury TS	---	4M13	250kW
720 Proudfoot Lane	Blackstone Energy Services Inc (Grant McArthur)	27.6kV	Talbot TS Desn 1	---	26M13	150kW
2724 Roxburgh Road	NorthGrid Solar (Julie Hand)	27.6kV	Buchanan TS	---	19M22	184kW
1010 Clarke Side Road	Horizon Energy Solutions (John Mayhew)	27.6kV	Clarke TS	---	70M6	250kW
900 Adelaide St South	Lumen Earth (Hamed Ghanbari)	27.6kV	Buchanan TS	---	19M23	110kW
300 Clarke Rd	Smylie & Crow Associates (Jason Allair)	27.6kV	Highbury TS	---	4M17	20kW
9070 **Elviage** Street	Ontario Solar Provider Inc (Ian Rice)	27.6kV	WONDERLAND TS	---	32M5	50kW
160 Adelaide St South	N//Ergy Solutions Inc.(Bill Moffat)	27.6kV	Buchanan TS	---	19M38	150kW
800 Commissioners Rd	Honeywell Ltd (Kyle Whittle)	27.6kV	Buchanan TS	---	19M25	75kW
90 Enterprise Drive	Shorex Earth Systems Inc (Cathy Marnoch)	27.6kV	Buchanan TS	---	19M27	200kW
425 Newbold St	Shorex Earth Systems Inc (Cathy Marnoch)	27.6kV	Buchanan TS	---	19M28	75kW
31 Firestone Blvd	Horizon Energy Solutions (John Mayhew)	27.6kV	Highbury TS	---	4M16	250kW
1100 Dundas St	**Connect Energy & Consulting (Yaakov (John) Kozak)**	27.6kV	Clarke TS	---	70M5	100kW
2323 Trafalgar St	German Solar Corp (Dennis German)	27.6Kv	Highbury TS	---	4M16	220kW
3026 Page St	German Solar Corp (Dennis German)	27.6Kv	Clarke TS	---	70M1	220kW

724 Fanshawe Park Rd. East	CAPREIT (Ofelia Guanlao)	27.6kV	Clarke TS	---	70M4	20kW
744 Fanshawe Park Rd. East	CAPREIT (Ofelia Guanlao)	27.6kV	Clarke TS	---	70M4	20kW
75 Fiddlers Green Rd.	CAPREIT (Ofelia Guanlao)	27.6kV	Talbot TS Desn 1	---	26M13	80kW
85 Fiddlers Green Rd.	CAPREIT (Ofelia Guanlao)	27.6kV	Talbot TS Desn 1	---	26M13	80kW
95 Fiddlers Green Rd.	CAPREIT (Ofelia Guanlao)	27.6kV	Talbot TS Desn 1	---	26M13	80kW
1010 Clarke Side Road	**Connect Energy & Consulting (Yaakov (John) Kozak)**	27.6kV	Clarke TS	---	70M6	250kW
200 Adelaide St South	N//Ergy Solutions Inc.(Ian Brown)	27.6kV	Buchanan TS	---	19M38	75kW
109 Fanshawe St. East	Efan Green Inc (Tim Ding)	27.6kV	Talbot TS Desn 1	---	26M21	165kW
50 North Centre Rd	Efan Green Inc (Tim Ding)	27.6kV	Talbot TS Desn 1	---	26M21	248kW
600 Third Street	NorthGrid Solar (Julie Hand)	27.6kV	Clarke TS	---	70M8	250kW
825 Wellington Rd	Efan Green Inc (Tim Ding)	27.6kV	Buchanan TS	---	19M24	86kW
148 Stronach Crescent	Toews Power Systems (Ken Toews)	27.6kV	Clarke TS	---	70M5	209kW
295 Rectory St	PQI Canada Limited (Steve Rankin,P.Eng)	27.6kV	Highbury TS	---	4M13	500kW
3040 Osler Street	Efan Green Inc (Tim Ding)	27.6kV	Clarke TS	---	70M1	250kW
327 Sovereign Road	Ontario Solar Provider Inc (Ian Rice)	27.6kV	Highbury TS	---	4M15	350kW
45 Enterprise Drive	Efan Green Inc (Tim Ding)	27.6kV	Buchanan TS	---	19M27	229kW
1400 Global Drive	OMNIWATT (Mike Wolowich)	27.6kV	Buchanan TS	---	19M27	500kW
1425 Max Brose Drive	OMNIWATT (Mike Wolowich)	27.6kV	Buchanan TS	---	19M27	500kW
3020 Gore Road	OMNIWATT (Mike Wolowich)	27.6kV	Highbury TS	---	4M15	250kW
530 Oxford Street	German Solar Corp (Dennis German)	27.6kV	Talbot TS Desn 2	---	26M42	500kW
611 Wonderland Road	German Solar Corp (Dennis German)	27.6kV	Talbot TS Desn 2	---	26M42	250kW
37 Intrepid Court	Energy One Solar Inc (Cathy Marnoch)	27.6kV	Highbury TS	---	4M14	50kW
900 Wilton Grove Road	Efan Green Inc (Tim Ding)	27.6kV	Buchanan TS	---	19M26	86kW
20 Gammage Street	Solar Power Network (Taylor McKay)	27.6kV	Clarke TS	---	70M5	250kW
230 Marconi Blvd	Solar Power Network (Taylor McKay)	27.6kV	Highbury TS	---	4M14	190kW
465 Castlegrove Blvd	Solar Power Network (Taylor McKay)	27.6kV	Talbot TS Desn 2	---	26M55	100kW
15600 Robins Hill Road	OMNIWATT (Mike Wolowich)	27.6kV	Clarke TS	---	70M1	500kW
8 Cuddy Blvd	Bio-en Power Inc (Earl Brubacher)	27.6kV	Clarke TS	---	70M1	2852kW
2867 Dundas Street	Ontario Solar Provider Inc (Ian Rice)	27.6kV	Clarke TS	---	70M1	80kW
2889 Dundas Street	Ontario Solar Provider Inc (Ian Rice)	27.6kV	Clarke TS	---	70M1	100kW
165 Emery St W	Solar Power Network (Taylor McKay)	4.16kV	Talbot TS Desn 2	22F4	26M41	90kW
30 Conway Drive	Solar Power Network (Taylor McKay)	27.6kV	Buchanan TS	---	19M23	105kW
403 Commissioners Rd W	Solar Power Network (Taylor McKay)	27.6kV	Talbot TS Desn 1	---	26M22	140kW
2106 Glanworth Drive	Mann Engineering Ltd (Joan Du)	8.32kV	Wonderland TS	97F2	32M6	100kW
346 Springbank Drive	Solart LLL Corp (Laura Wittebol)	27.6kV	Talbot TS Desn 1	---	26M22	12.35kW
145 Base line Road West	GTS Solar Solutions Inc. (Todd Wootton)	27.6kV	Talbot TS Desn 2	---	26M41	60kW

31 Firestone Blvd	QPA Solar Inc. (Richard Weston)	27.6kV	Highbury TS	---	4M16	500kW
3820 Commerce Road	Sun Edison (Anna Lauritzen)	27.6kV	Buchanan TS	---	19M22	52kW
3915 Commerce Road	Sun Edison (Anna Lauritzen)	27.6kV	Buchanan TS	---	19M22	161kW
1930 Mallard Rd	ES Tache Investments Ltd. (Dave Egles)	27.6kV	Talbot TS Desn 2	---	26M54	100kW
962 Leathorne	ES Tache Investments Ltd. (Dave Egles)	27.6kV	Buchanan TS	---	19M38	100kW
2106 Fanshawe Pk Rd East	QPA Solar Inc. (Richard Weston)	27.6kV	Clarke TS	---	70M4	10,000 kW
825 Bradley Ave	German Solar Corp (Dennis German)	27.6kV	Buchanan TS	---	19M28	500kW
185 Ashland Ave	Global Energy Solutions (Tracy Collins)	27.6kV	Buchanan TS	---	19M29	240kW
203 Bathurst Street	Global Energy Solutions (Tracy Collins)	27.6kV	Highbury TS	---	4M13	100kW
3700 Old Victoria Road	OSP - Ontario Solar Provider (Ian Rice)	27.6kV	Buchanan TS	---	19M21 HO cct	500kW
715 Fanshawe Park Road	Global Energy Solutions (Tracy Collins)	27.6kV	Talbot TS Desn 2	---	26M56	135kW
2724 Roxburgh Road	Northern Sun Energy (Craig Hanna)	27.6kV	Buchanan TS	---	19M22	100kW
459 Industrial Road	Solar Power Network (Taylor McKay)	27.6kV	Clarke TS	---	70M1	500kW
6320 Colonel Talbot Rd	Northern Sun Energy (Craig Hanna)	8.32kV	WONDERLAND TS	97F2	32M6	150kW
3410 White Oaks Road	Advanced Solar Investments (Kevin Peckford)	27.6kV	Buchanan TS	---	19M22	250kW
360 Exeter Road	Advanced Solar Investments (Kevin Peckford)	27.6kV	Buchanan TS	---	19M22	250kW
3660 White Oaks Road	Advanced Solar Investments (Kevin Peckford)	27.6kV	Buchanan TS	---	19M22	250kW
2022 Kains Rd	Northern Sun Energy (Craig Hanna)	27.6kV	Talbot TS Desn 1	---	26M13	120kW
2724 Roxburgh Road	N//Ergy Solutions Inc.(Ian Brown)	27.6kV	Buchanan TS	---	19M22	100kW
2800 Roxburgh Road	CarbonFree Technology (Antonio Antonopoulos)	27.6kV	Buchanan TS	---	19M22	250kW
4350 Castleton Road	CarbonFree Technology (Antonio Antonopoulos)	27.6kV	Buchanan TS	---	19M22	250kW
4575 Blakie Road	OSP - Ontario Solar Provider (Luke Slater)	27.6kV	WONDERLAND TS	---	32M1	500kW
37 Intrepid Court	Rumble Energy Inc. (Jared Hampden)	27.6kV	Highbury TS	---	4M14	50kW
3036 Page Street	Marnoch Energy Inc. (Cathy Marnoch)	27.6Kv	Clarke TS	---	70M1	180kW
1050 Hargrieve Road	Ozz Solar (Bobby MacCannell)	27.6kV	Buchanan TS	---	19M28	100kW
350 Sovereign Road	Ozz Solar (Bobby MacCannell)					100kW
375 Sovereign Road	Ozz Solar (Bobby MacCannell)					100kW
575 Industrial Road	Sky Solar Engineering (Frank Ruffolo)	27.6kV	Clarke TS	---	70M1	500kW
747 Hyde Park Road	SolPowered Energy Corp (Marc Viau)	27.6kV	Talbot TS Desn 2	---	26M54	75kW
1105 Wellington Road	Sun Edison (Anna Lauritzen)	27.6kV	Buchanan TS	---	19M28	280kW
1105 Wellington Road	Sun Edison (Anna Lauritzen)	27.6kV	Buchanan TS	---	19M23	280kW
1105 Wellington Road	Sun Edison (Anna Lauritzen)	27.6kV	Buchanan TS	---	19M23	280kW
1680 Richmond Street	Sun Edison (Anna Lauritzen)	27.6kV	Talbot TS Desn 2	---	26M46	430kW
1680 Richmond Street	Sun Edison (Anna Lauritzen)	27.6kV	Talbot TS Desn 1	---	26M21	430kW
330 Sovereign Road	Solar Power Network (Taylor McKay)	27.6kV	Highbury TS	---	4M15	130kW

695 Sovereign Road	Sonnen Pal Energy Inc. (Wade He)	27.6kV	Highbury TS	---	4M14	166kW
10 Artisan's Crescent	Solarize Energy LP (Ileana Olivar)	27.6kV	Clarke TS	---	70M1	75kW
151 Pine Valley Blvd	Sonnen Pal Energy Inc. (Wade He)	27.6kV	WONDERLAND TS	---	32M7	60kW
55 Mid Park Crescent	Greenlight Projects Inc. (Karl Repka)	27.6kV	Buchanan TS	---	19M27	100kW
1050 Kipps Ln	ESEI Solar Inc. (Grace An)	27.6kV	Clarke TS	---	70M7	40kW
140 Ann Street	ESEI Solar Inc. (Grace An)	27.6kV	Talbot TS Desn 1	---	26M14	100kW
695 Sovereign Road	Sol Energy Corp. (Stuart Murray)	27.6kV	Highbury TS	---	4M14	400kW
155 Tweedsmuir Avenue	Ameresco Canada Inc. (Rishi Poddar)	4.16kV	Highbury TS	18F2	4M16	50kW
225 Cairn Street	Ameresco Canada Inc. (Lea Poquerusse)	4.16kV	Buchanan TS	15F3	19M25	30kW
2727 Tokala Trail	Ameresco Canada Inc.(Cathy Cheung)	27.6kV	Talbot TS Desn 2	---	26M54	250kW
5200 Wellington Road South	Ameresco Canada Inc. (Rishi Poddar)	27.6kV	Buchanan TS	---	19M22	110kW
690 Viscount Road	Ameresco Canada Inc. (Rishi Poddar)	4.16kV	WONDERLAND TS	96F1	32M7	30kW
767 Valetta Street	Ameresco Canada Inc.(Cathy Cheung)	4.16kV	Talbot TS Desn 2	39F2	26M42	30kW
1440 Glenora Drive	Ameresco Canada Inc. (Flavia Harriott)	4.16kV	Talbot TS Desn 1	17F1	26M11	30kW
1958 Duluth Crescent	Ameresco Canada Inc. (Flavia Harriott)	27.6kV	Highbury TS	---	4M16	30kW
347 Lyle Street	Ameresco Canada Inc. (Flavia Harriott)	27.6kV	Highbury TS	---	4M13	30kW
430 Industrial Road	Solarize Energy LP (Ileana Olivar)	27.6kV	Clarke TS	---	70M1	150kW
218 Clarke Side Road	Ontario Solar Provider Inc (Kendra Marjerrison)	27.6kV	Highbury TS	---	4M16	100kW
4838 Colonel Talbot	Solar Power Network (Taylor McKay)	27.6kV	Wonderland TS	---	32M6	500kW
2552 Dingman Drive	Discovery Geo Energy (Chris Hall)	4.16kV	Buchanan TS	98F1	19M22	55kW
99 Dundas Street	Ontario Solar Provider Inc (Kendra Marjerrison)	13.8kV	Nelson TS DESN 1	---	13M1	150kW
1700 Hyde Park Road	Green Flow Energy (Brandon Taylor)	27.6kV	Talbot TS Desn 2	---	26M54	70kW
24 Braesyde Ave	MV Power Systems (Harold Vander Glas)	27.6kV	Highbury TS	---	4M15	169kW
6675 Burtwistle Lane	Solarfortis (Darin Wong)	27.6kV	Edgeware	---	27M2	1400kW
6675 Burtwistle Lane	Solarfortis (Darin Wong)	27.6kV	Edgeware	---	27M2	165kW
765 Exeter Road	Solarfortis (Darin Wong)	27.6kV	Buchanan TS	---	19M28	500kW
1588 Clarke Road	Joe Fontana	4.16kV	Clarke TS	83F1	70M3	2000kW
31 Buchanan Court	Amp Solar Group Inc (Kate Riley)	27.6kV	Buchanan TS	---	19M26	50kW
7236 Colonel Talbot	Amp Solar Group Inc (Kate Riley)	27.6kV	Edgeware	---	27M2	175kW
1005 Wilton Grove Road	Bright Power (Jamie Tremaine)	27.6kV	Buchanan TS	---	19M26	500kW
1030 Adelaide Street South	Bright Power (Jamie Tremaine)	27.6kV	Buchanan TS	---	19M28	500kW
1550 Trossacks Avenue	Blackstone Energy Services Inc (Bill Cotter)	27.6kV	Clarke TS	---	70M4	40kW
297 Baseline Road	Blackstone Energy Services Inc (Bill Cotter)	27.6kV	Buchanan TS	---	19M22	30kW

3435 White Oak Road	Bright Power (Jamie Tremaine)	27.6kV	Buchanan TS	---	19M22	250kW
35 Atlantic Court	Bright Power (Jamie Tremaine)	27.6kV	Highbury TS	---	4M17	135kW
470 Scenic Drive	Blackstone Energy Services Inc (Bill Cotter)	4.16kV	Buchanan TS	40F1	19M38	30kW
556 Wonderland Road	Solar Stream Green Energy Group (Lorraine Marshall)	27.6kV	Talbot TS Desn 2	---	26M42	250kW
677 Wharncliffe Road	Solar Stream Green Energy Group (Lorraine Marshall)	27.6kV	Wonderland TS	---	32M7	250kW
982 Hubrey Road	Bright Power (Jamie Tremaine)	27.6kV	Buchanan TS	---	19M27	250kW
529 Philips Street	Green Flow Energy (Brandon Taylor)	13.8kV	Nelson TS DESN 2	---	13M15	77kW
3435 White Oak Road	Solar Power Network (Taylor McKay)	27.6kV	Buchanan TS	---	19M22	250kW
35 Atlantic Court	Solar Power Network (Taylor McKay)	27.6kV	Highbury TS	---	4M17	135kW
4575 Blakie Road	German Solar Corp (Greg Edwards)	27.6kV	WONDERLAND TS	---	32M1	500kW
580 Industrial Road	Sun Edison (Anna Lauritzen)	27.6kV	Clarke TS	---	70M1	250kW
1717 Oxford Street East	Efan Green Inc (Tim Ding)	27.6kV	Clarke TS	---	70M8	250kW
396 Queens Ave	Blackstone Energy Services Inc (Bill Cotter)	27.6kV	Nelson TS DESN 2	8K6	13M33	30kW
554 First Street	Efan Green Inc (Tim Ding)	4.16kV	Highbury TS	29F1	4M18	130kW
565 Talbot St	Blackstone Energy Services Inc (Bill Cotter)	27.6kV	Talbot TS Desn 1	---	26M22	15kW
770 Wonderland Rd S	Blackstone Energy Services Inc (Bill Cotter)	27.6kV	Talbot TS Desn 1	---	26M25	20kW
1750 Crumlin Road	German Solar Corp (Greg Edwards)	27.6kV	Clarke TS	---	70M1	200kW
4300 Wellington Road	Solar Power Network (Luis Jaramillo)	27.6kV	Buchanan TS	---	19M22	250kW
1069 Clarke Road	Green Flow Energy (Brandon Taylor)	27.6kV	Clarke TS	---	70M5	60kW
3435 White Oak Road	Ontario Solar Provider Inc (Kendra Marjerrison)	27.6kV	Buchanan TS	---	19M22	250kW
931 Leathorne Street	Green Flow Energy (Brandon Taylor)	27.6kV	Buchanan TS	---	19M38	60kW
4838 Colonel Talbot	Solar Power Network (Luis Jaramillo)	27.6kV	Wonderland TS	---	32M6	500kW
6675 Burtwhistle Line	Canadian Solar (Markian Silecky)	27.6kV	Edgeware	---	27M2	135kW
645 Wilton Grove Rd	German Solar Corp (Greg Edwards)	27.6KVA	Buchanan TS	---	19M28	366 kW
35 Atlantic Court	Ontario Solar Provider Inc (Kendra Marjerrison)	27.6kV	Highbury TS	---	4M17	135kW
111 Baseline Road West	Whitney Engineering (Kyle McIntosh)	27.6kv	Talbot TS Desn 2	---	26M41	60kW
695 Talbot Street	Whitney Engineering (Kyle McIntosh)	27.6KVA	Talbot TS Desn 1	---	26M22	85kW
825 Bradley Ave	Whitney Engineering (Kyle McIntosh)	27.6kV	Buchanan TS	---	19M28	200kW
1010 Wilton Grove Rd	German Solar Corp (Greg Edwards)	27.6kV	Buchanan TS	---	19M22	180kW
1010-A Wilton Grove Rd	German Solar Corp (Greg Edwards)	27.6kV	Buchanan TS	---	19M22	108kW
1420 Global Dr	German Solar Corp (Greg Edwards)	27.6kV	Buchanan TS	---	19M27	120kW
15875 Robin's Hill Rd	German Solar Corp (Greg Edwards)	27.6kV	Clarke TS	---	70M1	120kW
1855 Oxford Street East	Ontario Solar Provider Inc (Kendra Marjerrison)	27.6kV	Clarke TS	---	70M8	70kW

3851 Commerce Rd	German Solar Corp (Greg Edwards)	27.6kV	Buchanan TS	---	19M27	120kW
645 Wilton Grove Rd	German Solar Corp (Greg Edwards)	27.6KVA	Buchanan TS	---	19M28	366 kW
3093 Glanworth Drive	Informed Energy Solutions Inc. (Gary Vida)	8.32kV	Wonderland TS	97F2	32M6	80kW
1840 Oxford Street East	JCM Capital (Jon Rathauser)	27.6kV	Clarke TS	---	70M8	500kW
84-88 Oakville Ave	Solar Stream Green Energy Group (Lorraine Marshall)	27.6kV	Clarke TS	---	70M3	250kW
1010 Clarke Road	Solar Power Network (Luis Jaramillo)	27.6kV	Clarke TS	---	70M6/M8	500kW
955 Wilton Grove Road	Stantec (Craig Wilson)	27.6kV	Buchanan TS	---	19M26	2500kW
1205 Green Valley Rd	German Solar Corp (Greg Edwards)	27.6kV	Buchanan TS	---	19M22	3000kW
1985 Gore Rd	German Solar Corp (Greg Edwards)	27.6kV	Highbury TS	---	4M15	5500kW
2040 Oxford St E	German Solar Corp (Greg Edwards)	27.6kV	Clarke TS	49F2	70M6	3000kW
15701 Robins Hill Road Bldg C	German Solar Corp (Greg Edwards)	27.6kV	Clarke TS	---	70M1	60kW
15911 Robins Hill Road Bldg G	German Solar Corp (Greg Edwards)	27.6kV	Clarke TS	---	70M1	198kW
2351 Huron Street Bldg E	German Solar Corp (Greg Edwards)	27.6kV	Clarke TS	---	70M1	80kW
4047 Dowell Drive	Solarize Energy LP (Ileana Olivar)	27.6kV	Buchanan TS	---	19M22	150kW
1050 Hargrieve Road	Potentia Solar (Michele Smith)	27.6kV	Buchanan TS	---	19M28	100kW
150 Simcoe Street	Sun Connect Canada (Susan Shaw)	13.8kV	Nelson TS DESN 2	1K3	13M34	500kW
335 Sovereign Road	Potentia Solar (Michele Smith)	27.6kV	Highbury TS	---	4M15	75kW
1104 Adelaide St North	Mann Engineering (Ryan Cheddi)	27.6kV	Clarke TS	---	70M7	112kW
1240 Commissioners Rd West	Mann Engineering (Ryan Cheddi)	27.6kV	Wonderland TS	---	32M8	250kW
6171 Colonel Talbot Rd	Arntjen Solar North America (Rich Wilton)	27.6kV	WONDERLAND TS	97F2	32M6	100kW
420 Neptune Crescent	Amp Solar Group Inc (Mona Travale)	27.6kV	Highbury TS	---	4M15	45kW
1120 Dearness Drive	Amp Solar Group Inc (Mona Travale)	27.6kV	Buchanan TS	---	19M28	50kW
3020 Gore Road	Shaka David	27.6kV	Highbury TS	---	4M15	200kW
1425 Max Brose Drive	KBRE Ltd (Jamie Kent)	27.6kV	Buchanan TS	---	19M27	3000kW
1100 Dundas St	Solar Power Network (Luis Jaramillo)	27.6kV	Clarke TS	---	70M5	499kW
23 Buchanan Court	Solar Power Network (Luis Jaramillo)	27.6kV	Buchanan TS	---	19M26	499kW
2809 Roxburgh Rd	Solar Power Network (Luis Jaramillo)	27.6kV	Buchanan TS	---	19M22	499kW
420 Burbrook Place	Solar Power Network (Luis Jaramillo)	27.6kV	Clarke TS	---	70M5	499kW
635 Wilton Grove Rd	Solar Power Network (Luis Jaramillo)	27.6kV	Buchanan TS	---	19M22	499kW
25 Cuddy Blvd	Glenbarra Energy Management Corp. (John Hamilton)	27.6kV	Clarke TS	---	70M1	200kW
2386 Main Street	New Solar Inc (Brian Young)	27.6kV	WONDERLAND TS	---	32M6	68kW
1200 Western Road	Ainsworth Inc (Rehab Rawoof)	27.6kV	Talbot TS Desn 2	---	26M55	140kW
1504 Highbury Ave	Renewable Power Plus (Emmanuel Azzopardi)	27.6kV	Clarke TS	---	70M4	170kW

955 Gainsborough Road	Synergy + Energy Solutions Inc (Todd Gillick)	27.6kV	Talbot TS Desn 2	---	26M54	150kW
4575 Blakie Road	Go Clean Go Green (Erik Rudy)	27.6kV	WONDERLAND TS	---	32M1	500kW
46 Firestone Blvd	Sol Energy Corp. (Stuart Murray)	27.6kV	Highbury TS	---	4M16	150kW
994 Hargrieve Road	Sun Connect Canada (Susan Shaw)	27.6kV	Buchanan TS	---	19M28	250kW
90 Enterprise Drive	ADELAIDE SOLAR ENERGY INC. (Dervla O'Reilly)	27.6kV	Buchanan TS	---	19M27	200kW
1020 Wonderland Road South	JCM Capital (Amar Kher)	27.6kV	WONDERLAND TS	---	32M7	150kW
1560 Hyde Park Road	QPA Solar Inc. (Marjan Stosic)	27.6kV	Talbot TS Desn 2	---	26M54	10kW
328 Commissioners Rd West	JCM Capital (Amar Kher)	27.6kV	Talbot TS Desn 1	93F1	26M22	50kW
665 Adelaide Street North	JCM Capital (Amar Kher)	27.6kV	Highbury TS	---	4M13	150kW
600 Oxford St West	Solar Tech Northern Lights (Joe D'Urzo)	27.6kV	Talbot TS Desn 2	---	26M42	250kW
1150 Wharncliffe South	Green Light Projects Inc. (Karl Repka)	27.6kV	WONDERLAND TS	---	32M4	250kW
6886 Colonel Talbot Road	Solar Stream Green Energy Group (Lorraine Marshall)	27.6kV	Edgeware	---	27M2	200kW
2290 Scanlan Street	Moose Power (Jamie Tremaine)	27.6kV	Highbury TS	---	4M15	500kW
5 Cuddy Blvd	Moose Power (Jamie Tremaine)	27.6kV	Clarke TS	---	70M1	500kW
White Oak Rd / 402	Sonnen Pal Energy Inc. (Wade He)	27.6kV	Wonderland TS	---	32M1	10,000 kW
Wonderland / 402	Sonnen Pal Energy Inc. (Wade He)	8.32kV	Wonderland TS	step down xfmr	32M1	10,000 kW
1921 Huron Street	Ontario Solar Provider Inc (Luke Slater)	27.6kV	Clarke TS	---	70M6	250kW
1045 Wonderland Rd. N.	Ameresco Canada Inc. (Rishi Poddar)	27.6kV	Talbot TS Desn 2	---	26M56	210kW
186 King Street	Solar Stream Green Energy Group (Lorraine Marshall)	13.8kV	Nelson TS DESN 1	---	13M3	50kW
817 Exeter Road	Solar Stream Green Energy Group (Lorraine Marshall)	27.6kV	Buchanan TS	---	19M28	500kW
370 Exeter Road	Built-Rite Energy Systems (Chris Campbell)	27.6kV	Buchanan TS	---	19M22	250kW
540 First Street	Solar Stream Green Energy Group (Lorraine Marshall)	27.6kV	Highbury TS	---	4M12	75kW
1105 Wellington Road	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M37	500kW
1105 Wellington Road	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M23	500kW
1105 Wellington Road	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M23	500kW
1164 Gainsborough Road	Arntjen Solar North America (Mike Meidlinger)	27.6kV	Talbot TS Desn 2	---	26M54	100kW
140 Clarke Road	Arntjen Solar North America (Mike Meidlinger)	4.16kV	Highbury TS	18F3	4M16	20kW
4056 Blakie Road	Arntjen Solar North America (Mike Meidlinger)	27.6kV	Wonderland TS	---	32M1	75kW
425 Newbold St	German Solar Corp (Robert Avison)	27.6kV	Buchanan TS	---	19M28	75kW
25 Cuddy Blvd	Glenbarra Energy Management Corp. (Gary Murakami)	27.6kV	Clarke TS	---	70M1	200kW
570 Industrial Road	Solar Power Network (Keith Richardson)	27.6kV	Clarke TS	---	70M1	425kW
85 MidPark Road	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M27	170kW

126 Clarke Road	Maple Solar Development Inc.(Jinwoo Song)	4.16kV	Highbury TS	18F3	4M16	150kW
2800 Roxburgh Road	CarbonFree Technology (Ven Seshadri)	27.6kV	Buchanan TS	---	19M22	250kW
4350 Castleton Road	CarbonFree Technology (Ven Seshadri)	27.6kV	Buchanan TS	---	19M22	250kW
300 Southdale Road East	Green Life Power (Mike Apostol)	27.6kV	Wonderland TS	---	32M7	100kW
640 Wonderland RoadNorth	Green Life Power (Mike Apostol)	27.6kV	Talbot TS Desn 2	---	26M42	150kW
363 Sovereign Road	Solar Power Network (Keith Richardson)	27.6kV	Highbury TS	---	4M15	325kW
76 Doulton Street	Solera Sustainable Energies Company (Shael Rotman)	27.6kV	Buchanan TS	---	19M29	55kW
7292 Colonel Talbot Road	Solar Power Network (Keith Richardson)	27.6kV	Edgeware	---	27M2	300kW
2552 Dingman Drive	Discovery Geo Energy (Jeff Schlueter)	4.16kV	Buchanan TS	98F1	19M22	55kW
2449 Dundas Street	Solar Power Network (Keith Richardson)	27.6kV	Clarke TS	---	70M1	275kW
1065 Wharncliffe Rd	Solera Sustainable Energies (Shael Rotman)	27.6kV	Wonderland TS	---	32M4	225.5kW
295 Rectory Street	Solarize Energy LP (Carlos Leite)	27.6kV	Highbury TS	---	4M13	250kW
4047 Dowell Drive	Solarize Energy LP (Carlos Leite)	27.6kV	Buchanan TS	---	19M22	150kW
430 Industrial Road	Solarize Energy LP (Carlos Leite)	27.6kV	Clarke TS	---	70M1	85kW
3502 Manning Drive	Ameresco Canada Inc. (Jim Fonger)	27.6kV	Wonderland TS	---	32M1	800kW
220 Sunnyside Drive	Ameresco Canada Inc.(Mary-Lynne Marino)	27.6kV	Talbot TS Desn 2	---	26M47	75kW
329 Hudson Drive	Ameresco Canada Inc.(Mary-Lynne Marino)	27.6kV	Highbury TS	---	4M14	60kW
690 Osgoode Drive	Ameresco Canada Inc.(Mary-Lynne Marino)	27.6kV	Buchanan TS	---	19M28	82kW
2552 Dingman Drive	SkyFire Energy (Danny Howard)	4.16kV	Buchanan TS	98F1	19M22	50kW
155 Tweedsmuir Avenue	Ameresco Canada Inc. (Rishi Poddar)	4.16kV	Highbury TS	18F2	4M16	50kW
170 Hawthorne Road	Ameresco Canada Inc.(Mary-Lynne Marino)	27.6kV	Talbot TS Desn 2	---	26M42	82kW
767 Valetta Street	Ameresco Canada Inc.(Cathy Cheung)	4.16kV	Talbot TS Desn 2	39F2	26M42	30kW
575 Industrial Road	Sky Solar Engineering (Frank Ruffolo)	27.6kV	Clarke TS	---	70M1	500kW
1440 Glenora Drive	Ameresco Canada Inc.(Cathy Cheung)	4.16kV	Talbot TS Desn 1	17F1	26M11	35kW
2330 Dundas Street	QPA Solar Inc. (Richard Weston)	27.6kV	Clarke TS	---	70M8	
347 Lyle Street	Ameresco Canada Inc.(Cathy Cheung)	27.6kV	Highbury TS	---	4M13	35kW
690 Viscount Road	Ameresco Canada Inc.(Cathy Cheung)	4.16kV	WONDERLAND TS	96F1	32M7	35kW
635 Wilton Grove Rd	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M22	500kW
1921 Huron Street	Solartgroup (Sunny Natalia)	27.6kV	Clarke TS	---	70M6	500kW
1958 Duluth Crescent	Ameresco Canada Inc.(Mary-Lynne Marino)	27.6kV	Highbury TS	---	4M16	35kW
225 Cairn Street	Ameresco Canada Inc.(Mary-Lynne Marino)	4.16kV	Buchanan TS	15F3	19M25	19.2kW
5250 Wellington Rd	Ameresco Canada Inc.(Mary-Lynne Marino)	27.6kV	Buchanan TS	---	19M22	100kW
25 Invicta Court	Icarus Power Generation Inc (Gus Kokkoros)	27.6kV	Buchanan TS	---	19M28	250kW

400 Newbold Street	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M28	400kW
110 Tower Line Place	SolPowered Energy Corp (Mike Perrault)	27.6kV	Buchanan TS	---	19M28	200kW
1961 Cedarhollow Blvd	QPA Solar Inc. (Richard Weston)	27.6kV	Clarke TS	---	70M4	90kW
31 Firestone Blvd	QPA Solar Inc. (Richard Weston)	27.6kV	Highbury TS	---	4M16	500kW
1036 Green Valley Road	Moose Power (Ephrem Chemali)	27.6kV	Buchanan TS	---	19M26	500kW
3959 Commerce Road	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M27	250kW
982 Hubrey Road	Moose Power (Ephrem Chemali)	27.6kV	Buchanan TS	---	19M27	250kW
99 Ash Street	Moose Power (Ephrem Chemali)	27.6KV	Highbury TS	---	4M13	250kW
1000 Clarke Road	Moose Power (Ephrem Chemali)	27.6kV	Clarke TS	---	70M6	500kW
1875 Wharncliffe Road South	Moose Power (Ephrem Chemali)	27.6kV	Wonderland TS		32M6	250kW
2400 Innovation Drive	Solarize Energy LP (Jeremy Leite)	27.6kV	Buchanan TS	---	19M30	250kW
2879 Innovation Drive	Solarize Energy LP (Jeremy Leite)	27.6kV	Buchanan TS	---	19M30	250kW
970 - 1020 Pond Mills Road	Moose Power (Ephrem Chemali)	27.6kV	Buchanan TS	---	19M27	500kW
993 Adelaide Street South	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M28	500kW
1065 Wharncliffe Road South	QPA Solar Inc. (Richard Weston)	27.6kV	Wonderland TS	---	32M4	234kW
590 Wharncliffe Road South	QPA Solar Inc. (Richard Weston)	27.6kV	Wonderland TS	---	32M7	142kW
601 Oxford Street West	QPA Solar Inc. (Richard Weston)	27.6kV	Talbot TS Desn 2	---	26M54	109kW
721 Hamilton Road	Mann Green Earth Rooftop LP (John Wong)	27.6KV	Highbury TS	---	4M13	47kW
4575 Blakie Road	Ray's Electric Inc (Don Payne)	27.6kV	WONDERLAND TS	---	32M1	250kW
111 - 117 Brydges Street	Gemco Solar Inc (Lorraine Howden)					150kW
110 Tower Line Place	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M28	250kW
30 Adelaide St North	Green Power Promotions (Andrew Hall-Holand)	13.8kV	Nelson TS DESN 2	---	13M15	100kW
765 Exeter Road	Eclipsall Solar Corp (Humayun Sheikh)	27.6kV	Buchanan TS	---	19M37	500kW
330 Sovereign Road	Solar Power Network (Keith Richardson)	27.6kV	Highbury TS	---	4M15	135kW
4300 Wellington Road	Solar Power Network (Keith Richardson)	27.6kV	Buchanan TS	---	19M22	250kW
1282 Hyde Park Road	Solarize Energy LP (Erin Cardy)	27.6kV	Talbot TS Desn 2	---	26M54	250kW
1804 Gore Road	Certified Solar (Aman Khera)	27.6kV	Highbury TS	18F3	4M16	260kW
1994 River Road	Certified Solar (Aman Khera)	27.6kV	Highbury TS	---	4M15	100kW
295 Rectory Street	Certified Solar (Aman Khera)	27.6kV	Highbury TS	---	4M13	500kW
2330 Scanlan Street	2318190 Ontario Ltd (Craig O'Brien)	27.6kV	Highbury TS	---	4M15	165kW
900 Wilton Grove Road	2318190 Ontario Ltd (Craig O'Brien)	27.6kV	Buchanan TS	---	19M26	75kW
982 Hubrey Road	2318190 Ontario Ltd (Craig O'Brien)	27.6kV	Buchanan TS	---	19M27	225kW
3410 White Oaks Road	RESCo Energy Inc (Daniel Kishimoto)	27.6kV	Buchanan TS	---	19M22	400kW
2200 Wharncliffe Road	Solar Power Network (Keith Richardson)	27.6kV	Wonderland TS	---	32M6	225kVA

1020 Wonderland Road South		27.6kV	WONDERLAND TS	---	32M7	150kW
1740 Richmond Street		27.6kV	Talbot TS Desn 1	---	26M12	135kW
448 CLARKE Side ROAD	Ozz Solar (Richard Di Bon)	27.6kV	Clarke TS	---	70M8	300kW
600 FANSHAWE PARK RD E	Ozz Solar (Richard Di Bon)	27.6kV	Talbot TS Desn 1	---	26M21	450kW
825 OXFORD STREET EAST		27.6kV	Clarke TS	---	70M5	375kW

APPENDIX B: 2013 Lost Revenue Adjustment Mechanism ("LRAM") Recoveries Rate Application Persistence of 2010 OPA CDM Programs

Response to Board Staff IR # 39: LRAM 2010 of Persistence 2010 OPA CDM Programs

1. Introduction

On May 31, 2004, the Minister of Energy granted approval to all distributors in Ontario to apply to the Ontario Energy Board (the "Board") for an increase in their 2005 rates by way of the third installment of their incremental market adjusted revenue requirement ("MARR"). This approval was conditional upon a commitment to reinvest in conservation and demand management ("CDM") an equivalent of one year's return. Consequently, in 2005 distributors, including London Hydro, brought forward, and the Board approved, $163 million in CDM funding for distributors, an amount related to the third tranche of their MARR.

In 2006 and through to 2012, London Hydro has received CDM funding from the Ontario Power Authority (the "OPA"). London Hydro's significant commitment to both CDM Programs and the achieving for customer efficiency in the use of energy London Hydro combined with the partnership of the OPA, has resulted in 2011 OPA verified 2011 to 2014 net cumulative energy savings of 84.04 GWh (representing 53.65% of London Hydro's 2011 to 2014 cumulative CDM energy target).

Previous to London Hydro's 2012 IRM rate application filing (EB-2011-0181), London Hydro had not applied for any recoveries for lost distribution revenues for either due to CDM programs funded from 3rd tranche MARR funding, or 2006, 2007, and 2008 CDM programs that were funded by the OPA. In Board's Decision and Order of London Hydro's 2012 IRM rate application (EB-2011-0181), it is stated, "*The Board approves an LRAM recovery of $152,652.49 representing lost revenues from 2010 CDM programs in the year 2010, as London was under IRM in this year and London has not otherwise received LRAM compensation for this year*". The Board further stated approval of, "*a one year disposition period for the LRAM recovery of $152,652.49*". The approved rate rider for lost revenue adjustment mechanism ("LRAM") recovery is effective

to April 30, 2013, as evidence in London Hydro's Tariff of Rates and Charges (Effective Date May 1, 2012).

In preparing this recovery of LRAM, London Hydro has followed the *Board's Guidelines for Electricity Distributor Conservation and Demand Management issued on March 28, 2008* (the "CDM Guidelines", EB-2008-0037). The Ontario Energy Board CDM Guidelines provide information on the Board's policies relating to Conservation and Demand Management activities undertaken by electricity distributors in Ontario, including the review and approval of claims for the LRAM recovery associated with distributors' CDM activities. Further, guidance was obtained by relying on the September 22, 2009 Decision and Order related to Toronto Hydro-Electric System Limited LRAM/ SSM application (the "Toronto Hydro 2007 Decision") granting approval and recovery of amount related to CDM activated in 2007 (EB-2008-0401).

The Board updated the CDM Guidelines on April 26, 2012 and the filing requirements on June 28, 2012 for LRAM claims for pre-2011 CDM activities. In Section 13.6 of the Board Guidelines states, " *The Board expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service".*

London Hydro's last approved Cost of Service Rate Application was for 2009 (EB-2008-0235).

The purpose of the 2013 requested LRAM riders would be to recover 2011 and 2012 lost distribution revenues due to persistent 2010 CDM programs funded by the OPA. London has not in the past applied for a Shared Savings Mechanism

("SSM") rate rider as the Board's Guidelines indicate SSM is only available for programs that are funded through distribution rates.

Therefore, London Hydro is applying to the Board for the approval to recover a LRAM amount of $266,877.56, including carrying costs.

2. 2010 OPA Programs

The OPA has provided London Hydro with the 2011 verified results for all OPA funded programs for 2010. Details are provided as to 2010 OPA CDM Programs attached to this Appendix, as well as 2011 OPA CDM Programs are included in excel filing titled, LondonHydro_ Copy of 2011_Final_Annual_Report_Data_CDM_OPAPrograms_20130108. For efficiency purposes, only the results applicable to 2009 through 2013 are shown in the attached 2010 OPA verified results spreadsheet, although 25 years were provided.

The Board's Guidelines states "The LRAM applies to programs implemented by the distributor, within its licensed service area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party" (Pg. 18, Board's Guidelines for Electricity Distributor Conservation and Demand Management issued on March 28, 2008).

The CDM programs that London Hydro delivered through the OPA in 2009 in the London Hydro service territory were:

- The Great Refrigerator Roundup Program ("GRRP"),
- Every Kilowatt Counts ("EKC") Power Savings Event,

- Cool Savings Rebate Program ("CSRP"),
- High Performance New Construction,
- Demand Response Programs,
- Energy Retrofit Incentive Program "ERIP", and
- Power Savings Blitz.

A brief description of each program is provided below:

- GRRP was a province-wide energy efficiency initiative designed to act as the catalyst for the removal of older, inefficient appliances from the homes of residential electricity consumers. The removal of second full sized refrigerators or freezers was the GRRP's primary focus, with a secondary focus on room air conditioners and smaller "bar" style refrigerators or freezers.

- EKC was a province-wide education and incentive program targeted at Ontario's residential households. The goal of the program was to provide Ontario homeowners and tenants with the necessary tools and information to save electricity and to have a positive impact on the environment by inducing customers to implement 'easy to do' and 'low cost' energy saving measures.

London Hydro delivered both the spring and fall campaigns in its service territory. The products for which discount coupons were provided in the Spring campaign included Energy Star® Specialty compact fluorescent lights ("CFLs"), clothes lines, plug-in pool timers, Energy Star® light fixtures, window film, pipe wrap, Energy Star® ceiling fans and water heater blankets. The products for which coupons were provided in the Fall campaign were Energy Star® Specialty CFLs/ electric baseboard programmable thermostats, Energy Star® light fixtures, lighting and appliance controls, water heater blankets, pipe wrap and weather stripping.

• CSRP, managed by the Heating, Refrigeration and Air Conditioning Institute of Canada, offered incentives to motivate consumer purchases of ENERGY STAR® qualified central air conditioning, furnaces and programmable thermostats.

• The High Performance New Construction program provides design assistance and financial incentives for building owners and architects who exceed the electricity efficiency standards specified in the Ontario Building Code.

• Demand Response programs compensate industrial and commercial businesses for reducing their energy demand at specific time of power system need.

• ERIP provides a substantial financial incentive to businesses for replacing existing equipment with high efficiency equipment and for installing new control systems that improve the efficiency for operational procedures and processes.

• The Power Savings Blitz program is designed to install energy efficient equipment (lighting and water heating upgrades) in small businesses at no cost to the owners, up to $1,000.

In Table 2, OPA CDM Load Impacts 2010 OPA Programs for which London Hydro is seeking a LRAM recovery in 2013. The table indicates the kWh and Kw impacts (both in gross and net of free riders) for the years 2011 and 2012.

Although many of the OPA energy conservation and demand management programs are specific to a rate class, the Electricity Retrofit Incentive Programs (ERIP, and its successor the saveONenergy RETROFIT Program) does span

several customer classes, namely general service less than 50 kW, and general service greater than 50 kW.

Reviewing our records and the information as submitted to the OPA, for ERIP projects carried within our service territory during 2010, the division of gross kW reductions amongst customer classes was:

Table 2, 2010 ERIP Gross Demand Reduction (within London)

Customer Classification	Gross kW Demand Reduction	Percentage
General Service Less Than 50 kW	316	8.2%
General Service Greater Than 50 kW	3,554	91.7%
Large User	0	0%
Total:	**3,874**	**99.9%**

**For the purposes of reflecting 100% totals for the above allocations, the 0.1% balance will be allocated to general service greater than 50 kW.*

TABLE 1 – kWh and Kw Allocation of ERIP Program to Customer Classes for 2010

ERIP ALLOCATION:		2011		2011		2012		2012	
From OPA Verified Results (see Tab ERIP Savings)		NET		GROSS		NET		GROSS	
** Used 2011 OPA verified results as proxy for 2012.		1,419,000	252	2,798,000	480.0				
Allocation of Retrofit kWh (GS 50 and Kw Demand)	2010	1,419,000	252.0	2,798,000	480.0				
GS < 50	8.2%	116,358	20.7	229,436	39.4				
GS 1,000 to 4,999 kW	91.8%	1,302,642	231.3	2,568,564	440.6				
		1,419,000	252.0	2,798,000	480.0				
	2010	-		-		1,419,000	252.0	2,798,000	480.0
GS < 50	8.2%	-	-	-	-	116,358	20.7	229,436	39.4
GS 1,000 to 4,999 kW	91.8%	-	-	-	-	1,302,642	231.3	2,568,564	440.6
						1,419,000	252.0	2,798,000	480.0

TABLE 2 – OPA CDM Program Load Impacts (2010)

*London Hydro is not requesting LRAM /SSM for Programs in 2006, 2007, and 2008. Programs in 2009 were also not included

		2011 NET		2011 GROSS			2012 NET		2012 GROSS		TOTAL NET		TOTAL GROSS	
Class/ Program	Year Program Implimented	kWh	Kw	kWh	Kw		kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw
RESIDENTIAL														
Great Refrigerator Roundup	2010	1,313,000	201.0	2,471,000	395.0		1,313,000	201.0	2,471,000	395.0	2,626,000	402.0	4,942,000	790.0
Cool Savings Rebate	2010	1,228,000	811.0	2,855,000	1,826.0		1,228,000	811.0	2,855,000	1,826.0	2,456,000	1,622.0	5,710,000	3,652.0
Every Kilowatt Counts Power Savings Event	2010	473,000	46.0	1,161,000	112.0		458,000	46.0	1,159,000	112.0	931,000	92.0	2,320,000	224.0
Residential Total		3,014,000	1,058.0	6,487,000	2,333.0		2,999,000	1,058.0	6,485,000	2,333.0	6,013,000	2,116.0	12,972,000	4,666.0
General Service < 50 kW														
OPA Energy Retrofit Incentive Program (ERIP)	2010	116,358	21	229,436	39		116,358	20.7	229,436	39.4	232,716	41.3	458,872	78.7
High Performance New Construction	2010	839,000	368.0	1,198,000	525.0		839,000	368.0	1,198,000	525.0	1,678,000	736.0	2,396,000	1,050.0
Power Savings Blitz	2010	7,485,000	2,439.0	7,560,000	2,464.0		7,485,000	2,439.0	7,560,000	2,464.0	14,970,000	4,878.0	15,120,000	4,928.0
MultiFamily Energy Efficency Rebates	2010	1,244,000	105.0	1,689,000	138.0		1,244,000	105.0	1,689,000	138.0	2,488,000	210.0	3,378,000	276.0
Total General Service < 50 kW		9,684,358	2,932.7	10,676,436	3,166.4		9,684,358	2,932.7	10,676,436	3,166.4	19,368,716	5,865.3	21,352,872	6,332.7
General Service 50 kW to 4,999 kW														
OPA Energy Retrofit Incentive Program (ERIP)	2010	1,302,642	231.3	2,568,564	440.6		1,302,642	231.3	2,568,564	440.6	2,605,284	462.7	5,137,128	881.3
Demand Response 1	2010	0	0.0	0	0.0		0	0.0	0	0.0	0	0.0	0	0.0
Total General Service 50 to 4,999 kW		1,302,642	231.3	2,568,564	440.6		1,302,642	231.3	2,568,564	440.6	2,605,284	462.7	5,137,128	881.3
Total Load Impacts from OPA programs		14,001,000	4,222	19,732,000	5,940	0	13,986,000	4,222	19,730,000	5,940	27,987,000	8,444	39,462,000	11,880

3. Forgone Revenues

For the 2013 LRAM resulting from actual 2010 OPA programs, London Hydro has reflected the OPA confirmed energy savings by OPA program and by customer class and valued these savings using the appropriate variable distribution charge (per kWh or kW, as applicable), and not including any Regulatory Asset Recovery rate rider.

TABLE 3 – Forgone Revenue by Program and Class

Forgone Revenue by Program and Class
(2010 OPA Programs Only)

*London Hydro is not requesting LRAM /SSM for Programs in 2006, 2007, and 2008. Programs in 2009 were also not included

		2011				2012				Total Revenue
Class/ Program	Year Program Implimented	Load Impact	kWh or kW	Rate per Unit	Revenue	Load Impact	kWh or kW	Rate per Unit	Revenue	
RESIDENTIAL										
Great Refrigerator Roundup	2010	1,313,000	kWh	$ 0.0142	$ 18,644.60	1,313,000	kWh	$ 0.0143	$ 18,775.90	$ 37,420.50
Cool Savings Rebate	2010	1,228,000	kWh	$ 0.0142	$ 17,437.60	1,228,000	kWh	$ 0.0143	$ 17,560.40	$ 34,998.00
Every Kilowatt Counts Power Savings Event	2010	473,000	kWh	$ 0.0142	$ 6,716.60	458,000	kWh	$ 0.0143	$ 6,549.40	$ 13,266.00
Residential Total		3,014,000			$ 42,798.80	2,999,000			$ 42,885.70	$ 85,684.50
General Service < 50 kW										
OPA Energy Retrofit Incetive Program (ERIP)	2010	116,358	kWh	$ 0.0091	$ 1,058.86	116,358	kWh	$ 0.0092	$ 1,070.49	$ 2,129.35
High Performance New Construction	2010	839,000	kWh	$ 0.0091	$ 7,634.90	839,000	kWh	$ 0.0092	$ 7,718.80	$ 15,353.70
Power Savings Blitz	2010	7,485,000	kWh	$ 0.0091	$ 68,113.50	7,485,000	kWh	$ 0.0092	$ 68,862.00	$ 136,975.50
MultiFamily Energy Efficency Rebates	2010	1,244,000	kWh	$ 0.0091	$ 11,320.40	1,244,000	kWh	$ 0.0092	$ 11,444.80	$ 22,765.20
Total General Service < 50 kW		9,684,358			$ 88,127.66	9,684,358			$ 89,096.09	$ 177,223.75
General Service 50 kW to 4,999 kW										
OPA Energy Retrofit Incetive Program (ERIP)		231.3	kW	$ 1.6081	$ 372.01	231	kW	$ 1.6223	$ 375.30	$ 747.31
Demand Response 1	2010	0	kW	$ 1.6081	$ -	0	kW	$ 1.6223	$ -	$ -
Total General Service 50 to 4,999 kW		231			$ 372.01	231			$ 375.30	$ 747.31
Total Forgone Revenue OPA programs		12,698,589			$ 131,298.47	12,683,589			$ 132,357.09	$ 263,655.56

4. Carrying Charges

In the Toronto Hydro Decision, the Board found that Toronto Hydro was entitled to carrying charges on the LRAM balances. London Hydro has calculated carrying charges as follows: interest has been applied to the ending balance of the annual LRAM for all of
2011 and 2012.The calculation of the carrying costs used the Board's prescribed interest rates for Q1 2011 – Q1 2013, as shown in Table 4.

Table 4 – Board's Prescribed Interest Rates and Calculated Interest

	Q1 2012	Q2 2013	Q3 2012	Q4 2012	4 Months to April 30, 2013	Total
%	1.47	1.47	1.47	1.47	1.47	
Residential ($)	$ 157	$ 157	$ 157	$ 157	$ 420	$ 1,049.00
GS < 50 kW ($)	$ 324	$ 324	$ 324	$ 324	$ 868	$ 2,163.87
GS 50 to 4,999 kW ($)	$ 1	$ 1	$ 1	$ 1	$ 4	$ 9.13

5. Calculation of Rate Rider

The amount of relief request for LRAM is an amount of $263,655.56, plus $3,222.00 carrying charges.

The LRAM rate rider being applied, as calculated in Table 5 – LRAM Rate Riders, includes LRAM as reflected in Table 3 – Forgone Revenue by Program by Class, and Carrying Charges as reflected in Table 4 – Board's Prescribed Interest Rates and Calculated Interest. The Billing Determines is actual distribution energy quantities (kWh or kW) for 2011.

Table 5 – LRAM Rate Riders for 2013

Class	Units	LRAM	Carrying Charges	Total	2011 Billing Determines	Rate Rider
Residential	kWh	$ 85,685	$ 1,049	$ 86,734	1,128,904,736	$ 0.0001
GS < 50 kW	kWh	$ 177,224	$ 2,164	$ 179,388	408,115,902	$ 0.0004
GS 50 to 4,999 kW	kW	$ 747	$ 9	$ 756	3,944,476	$ 0.0002
Totals		$ 263,656	$ 3,222	$ 266,878		

Billing Deteminates used 2011 Distribution Energy Quantities (Actual)

London Hydro is requesting a volumetric LRAM specific rate rider be established to collect the total recovery amount. The proposed rate rider is over a one-year period, effective May 1, 2013.

Therefore, London Hydro is requesting approval for a LRAM volumetric rate rider of $0.0001/kWh for the Residential class and $0.0004/kWh for General Service > 50 kW Class, and $0.0002/kW for General Service 50 to 4,999 kW Class.

6. Third party Verification

Section 7.5 of the Board's Guidelines requires that distributors should engage an independent third party to review the program evaluations prepared for the purposes of LRAM claims filed with the Board. The Guidelines state "This independent third party review applies to LRAM and SSM claims made in relation to programs funded in 2007 and beyond", but goes on to say "The Board would

consider an evaluation by the OPA or a third party designated by the OPA to be sufficient. For programs funded by the OPA, it will be the role of the third party to:

- Verify the participation levels, and,
- Confirm that input assumptions are those used by the OPA“

OPA – 2010 Final Annual CDM Results London Hydro Inc.

OPA Conservation & Demand Management Programs

Initiative Results at End-User Level

For: London Hydro Inc.

Net Summer Peak Demand Savings (MW)

#	Initiative Name	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	Secondary Refrigerator Retirement Pilot	Consumer	2006	Final	0.034	0.034	0.034	0.034	0.034	0.034	0.000	0.000
2	Cool & Hot Savings Rebate	Consumer	2006	Final	0.346	0.346	0.346	0.346	0.346	0.346	0.346	0.346
3	Every Kilowatt Counts	Consumer	2006	Final	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114
4	Demand Response 1	Business, Industrial	2006	Final	7.633	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	Loblaw & York Region Demand Response	Business, Industrial	2006	Final	0.374	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	Great Refrigerator Roundup	Consumer	2007	Final	0.000	0.061	0.061	0.061	0.061	0.054	0.054	0.054
7	Cool & Hot Savings Rebate	Consumer	2007	Final	0.000	0.396	0.396	0.396	0.396	0.396	0.365	0.365
8	Every Kilowatt Counts	Consumer	2007	Final	0.000	0.138	0.125	0.125	0.125	0.125	0.125	0.125
9	***peaksaver®***	Consumer, Business	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	Summer Savings	Consumer	2007	Final	0.000	1.835	0.547	0.263	0.263	0.263	0.263	0.263
11	Aboriginal	Consumer	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	Affordable Housing Pilot	Consumer Low-Income	2007	Final	0.000	0.005	0.005	0.005	0.005	0.005	0.005	0.005
13	Social Housing Pilot	Consumer Low-Income	2007	Final	0.000	0.038	0.038	0.038	0.038	0.038	0.038	0.038
14	Energy Efficiency Assistance for Houses Pilot	Consumer Low-Income	2007	Final	0.000	0.003	0.003	0.003	0.003	0.003	0.003	0.003
15	Electricity Retrofit Incentive	Business	2007	Final	0.000	1.252	1.252	1.252	1.252	1.252	0.000	0.000
16	Toronto Comprehensive	Business	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17	Demand Response 1	Business, Industrial	2007	Final	0.000	8.634	0.000	0.000	0.000	0.000	0.000	0.000
18	Loblaw & York Region Demand Response	Business, Industrial	2007	Final	0.000	0.718	0.000	0.000	0.000	0.000	0.000	0.000
19	Renewable Energy Standard Offer	Consumer, Business, Industrial	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20	Great Refrigerator Roundup	Consumer	2008	Final	0.000	0.000	0.130	0.130	0.130	0.130	0.125	0.125
21	Cool Savings Rebate	Consumer	2008	Final	0.000	0.000	0.408	0.408	0.408	0.408	0.408	0.408
22	Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0.000	0.000	0.178	0.170	0.170	0.170	0.155	0.155
23	***peaksaver®***	Consumer, Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	Summer Sweepstakes	Consumer	2008	Final	0.000	0.000	0.721	0.414	0.414	0.414	0.414	0.414
25	Electricity Retrofit Incentive	Consumer, Business	2008	Final	0.000	0.000	1.998	1.998	1.998	1.998	1.998	1.998
26	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
27	High Performance New Construction	Business	2008	Final	0.000	0.000	0.009	0.009	0.009	0.009	0.009	0.009
28	Power Savings Blitz	Business	2008	Final	0.000	0.000	0.003	0.003	0.001	0.001	0.001	0.001
29	Demand Response 1	Business, Industrial	2008	Final	0.000	0.000	11.893	0.000	0.000	0.000	0.000	0.000
30	Demand Response 3	Business, Industrial	2008	Final	0.000	0.000	2.300	0.000	0.000	0.000	0.000	0.000
31	Loblaw & York Region Demand Response	Business, Industrial	2008	Final	0.000	0.000	0.790	0.000	0.000	0.000	0.000	0.000
32	Renewable Energy Standard Offer	Consumer, Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
33	Other Customer Based Generation	Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
34	LDC Custom - Hydro One Networks Inc. - Double R	Business, Industrial	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
35	Great Refrigerator Roundup	Consumer	2009	Final	0.000	0.000	0.000	0.187	0.187	0.187	0.179	0.131
36	Cool Savings Rebate	Consumer	2009	Final	0.000	0.000	0.000	0.512	0.512	0.512	0.510	0.510
37	Every Kilowatt Counts Power Savings Event	Consumer	2009	Final	0.000	0.000	0.000	0.137	0.135	0.135	0.135	0.134
38	***peaksaver®***	Consumer, Business	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
39	Electricity Retrofit Incentive	Consumer, Business	2009	Final	0.000	0.000	0.000	1.602	1.602	1.602	1.602	1.602
40	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
41	High Performance New Construction	Business	2009	Final	0.000	0.000	0.000	0.103	0.103	0.103	0.103	0.103
42	Power Savings Blitz	Business	2009	Final	0.000	0.000	0.000	0.836	0.836	0.836	0.836	0.836
43	Multi-Family Energy Efficiency Rebates	Consumer, Consumer Low-Income	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
44	Demand Response 1	Business, Industrial	2009	Final	0.000	0.000	0.000	4.648	0.000	0.000	0.000	0.000
45	Demand Response 2	Business, Industrial	2009	Final	0.000	0.000	0.000	3.156	0.000	0.000	0.000	0.000
46	Demand Response 3	Business, Industrial	2009	Final	0.000	0.000	0.000	4.508	0.000	0.000	0.000	0.000
47	Loblaw & York Region Demand Response	Business, Industrial	2009	Final	0.000	0.000	0.000	0.775	0.000	0.000	0.000	0.000
48	LDC Custom - Thunder Bay Hydro - Phantom Load	Consumer	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
49	LDC Custom - Toronto Hydro - Summer Challenge	Consumer	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
50	LDC Custom - PowerStream - Data Centers	Business	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
51	Toronto Comprehensive Adjustment	Consumer, Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
52	LDC Custom - Hydro One Networks Inc. - Double R	Business, Industrial	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
53	Great Refrigerator Roundup	Consumer	2010	Final	0.000	0.000	0.000	0.000	0.201	0.201	0.201	0.195
54	Cool Savings Rebate	Consumer	2010	Final	0.000	0.000	0.000	0.000	0.811	0.811	0.811	0.811
55	Every Kilowatt Counts Power Savings Event	Consumer	2010	Final	0.000	0.000	0.000	0.000	0.048	0.046	0.045	0.045
56	***peaksaver®***	Consumer, Business	2010	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
57	Electricity Retrofit Incentive	Consumer, Business	2010	Final	0.000	0.000	0.000	0.000	0.252	0.252	0.252	0.252
58	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2010	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
59	High Performance New Construction	Business	2010	Final	0.000	0.000	0.000	0.000	0.368	0.368	0.368	0.368
60	Power Savings Blitz	Business	2010	Final	0.000	0.000	0.000	0.000	2.439	2.439	2.439	2.439
61	Multi-Family Energy Efficiency Rebates	Consumer, Consumer Low-Income	2010	Final	0.000	0.000	0.000	0.000	0.105	0.105	0.105	0.105
62	Demand Response 2	Business, Industrial	2010	Final	0.000	0.000	0.000	0.000	3.391	0.000	0.000	0.000
63	Demand Response 3	Business, Industrial	2010	Final	0.000	0.000	0.000	0.000	7.171	0.000	0.000	0.000
64	Loblaw & York Region Demand Response	Business, Industrial	2010	Final	0.000	0.000	0.000	0.000	0.832	0.000	0.000	0.000
65	LDC Custom - Hydro Ottawa - Small Commercial D	Consumer	2010	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2006 Subtotal					**8.50**	**0.49**	**0.49**	**0.49**	**0.49**	**0.49**	**0.46**	**0.46**
2007 Subtotal					**0.00**	**13.08**	**2.43**	**2.14**	**2.14**	**2.14**	**0.85**	**0.85**
2008 Subtotal					**0.00**	**0.00**	**18.43**	**3.13**	**3.13**	**3.13**	**3.11**	**3.11**
2009 Subtotal					**0.00**	**0.00**	**0.00**	**16.46**	**3.37**	**3.37**	**3.36**	**3.32**
2010 Subtotal					**0.00**	**0.00**	**0.00**	**0.00**	**15.62**	**4.22**	**4.22**	**4.21**
Overall Total					**8.50**	**13.57**	**21.35**	**22.23**	**24.76**	**13.36**	**12.01**	**11.95**

Net Energy Savings (MWh)

#	Initiative Name	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	Secondary Refrigerator Retirement Pilot	Consumer	2006	Final	151	151	151	151	151	151	0	0
2	Cool & Hot Savings Rebate	Consumer	2006	Final	373	373	373	373	373	373	373	373
3	Every Kilowatt Counts	Consumer	2006	Final	9,679	9,679	9,679	9,679	1,248	1,248	1,248	1,248
4	Demand Response 1	Business, Industrial	2006	Final	0	0	0	0	0	0	0	0
5	Loblaw & York Region Demand Response	Business, Industrial	2006	Final	0	0	0	0	0	0	0	0
6	Great Refrigerator Roundup	Consumer	2007	Final	0	480	480	480	480	479	477	477
7	Cool & Hot Savings Rebate	Consumer	2007	Final	0	593	593	593	593	593	565	565
8	Every Kilowatt Counts	Consumer	2007	Final	0	3,557	3,513	3,513	3,513	3,513	3,393	3,393
9	***peaksaver®***	Consumer, Business	2007	Final	0	0	0	0	0	0	0	0
10	Summer Savings	Consumer	2007	Final	0	3,277	552	209	209	209	209	209
11	Aboriginal	Consumer	2007	Final	0	0	0	0	0	0	0	0
12	Affordable Housing Pilot	Consumer Low-Income	2007	Final	0	8	8	8	8	8	8	8
13	Social Housing Pilot	Consumer Low-Income	2007	Final	0	323	323	323	323	323	323	323
14	Energy Efficiency Assistance for Houses Pilot	Consumer Low-Income	2007	Final	0	4	4	4	4	4	4	4
15	Electricity Retrofit Incentive	Business	2007	Final	0	3,479	3,479	3,479	3,479	3,479	0	0
16	Toronto Comprehensive	Business	2007	Final	0	0	0	0	0	0	0	0
17	Demand Response 1	Business, Industrial	2007	Final	0	0	0	0	0	0	0	0
18	Loblaw & York Region Demand Response	Business, Industrial	2007	Final	0	0	0	0	0	0	0	0
19	Renewable Energy Standard Offer	Consumer, Business, Industrial	2007	Final	0	0	0	0	0	0	0	0
20	Great Refrigerator Roundup	Consumer	2008	Final	0	0	1,199	1,199	1,199	1,199	1,197	1,194
21	Cool Savings Rebate	Consumer	2008	Final	0	0	644	644	644	644	644	644
22	Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0	0	3,271	3,257	3,257	3,257	2,765	2,765
23	***peaksaver®***	Consumer, Business	2008	Final	0	0	0	0	0	0	0	0
24	Summer Sweepstakes	Consumer	2008	Final	0	0	2,851	1,029	1,029	1,029	1,029	1,029
25	Electricity Retrofit Incentive	Consumer, Business	2008	Final	0	0	12,385	12,385	12,385	12,385	12,385	12,385
26	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2008	Final	0	0	0	0	0	0	0	0
27	High Performance New Construction	Business	2008	Final	0	0	8	8	8	8	8	8
28	Power Savings Blitz	Business	2008	Final	0	0	22	22	9	9	9	9
29	Demand Response 1	Business, Industrial	2008	Final	0	0	0	0	0	0	0	0
30	Demand Response 3	Business, Industrial	2008	Final	0	0	0	0	0	0	0	0
31	Loblaw & York Region Demand Response	Business, Industrial	2008	Final	0	0	0	0	0	0	0	0
32	Renewable Energy Standard Offer	Consumer, Business	2008	Final	0	0	0	0	0	0	0	0
33	Other Customer Based Generation	Business	2008	Final	0	0	0	0	0	0	0	0
34	LDC Custom - Hydro One Networks Inc. - Double R	Business, Industrial	2008	Final	0	0	0	0	0	0	0	0
35	Great Refrigerator Roundup	Consumer	2009	Final	0	0	0	1,243	1,243	1,243	1,236	938
36	Cool Savings Rebate	Consumer	2009	Final	0	0	0	778	778	778	775	771
37	Every Kilowatt Counts Power Savings Event	Consumer	2009	Final	0	0	0	1,353	1,297	1,297	1,296	1,288
38	***peaksaver®***	Consumer, Business	2009	Final	0	0	0	0	0	0	0	0
39	Electricity Retrofit Incentive	Consumer, Business	2009	Final	0	0	0	11,850	11,850	11,850	11,850	11,850
40	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2009	Final	0	0	0	0	0	0	0	0
41	High Performance New Construction	Business	2009	Final	0	0	0	235	235	235	235	235
42	Power Savings Blitz	Business	2009	Final	0	0	0	3,260	3,260	3,260	3,260	3,260
43	Multi-Family Energy Efficiency Rebates	Consumer, Consumer Low-Income	2009	Final	0	0	0	0	0	0	0	0
44	Demand Response 1	Business, Industrial	2009	Final	0	0	0	204	0	0	0	0
45	Demand Response 2	Business, Industrial	2009	Final	0	0	0	1,944	0	0	0	0
46	Demand Response 3	Business, Industrial	2009	Final	0	0	0	37	0	0	0	0
47	Loblaw & York Region Demand Response	Business, Industrial	2009	Final	0	0	0	0	0	0	0	0
48	LDC Custom - Thunder Bay Hydro - Phantom Load	Consumer	2009	Final	0	0	0	0	0	0	0	0
49	LDC Custom - Toronto Hydro - Summer Challenge	Consumer	2009	Final	0	0	0	0	0	0	0	0
50	LDC Custom - PowerStream - Data Centers	Business	2009	Final	0	0	0	0	0	0	0	0
51	Toronto Comprehensive Adjustment	Consumer, Business	2008	Final	0	0	0	0	0	0	0	0
52	LDC Custom - Hydro One Networks Inc. - Double R	Business, Industrial	2008	Final	0	0	0	0	0	0	0	0
53	Great Refrigerator Roundup	Consumer	2010	Final	0	0	0	0	1,313	1,313	1,313	1,308
54	Cool Savings Rebate	Consumer	2010	Final	0	0	0	0	1,228	1,228	1,228	1,228
55	Every Kilowatt Counts Power Savings Event	Consumer	2010	Final	0	0	0	0	539	473	458	458
56	***peaksaver®***	Consumer, Business	2010	Final	0	0	0	0	0	0	0	0
57	Electricity Retrofit Incentive	Consumer, Business	2010	Final	0	0	0	0	1,419	1,419	1,419	1,419
58	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2010	Final	0	0	0	0	0	0	0	0
59	High Performance New Construction	Business	2010	Final	0	0	0	0	839	839	839	839
60	Power Savings Blitz	Business	2010	Final	0	0	0	0	7,485	7,485	7,485	7,485
61	Multi-Family Energy Efficiency Rebates	Consumer, Consumer Low-Income	2010	Final	0	0	0	0	1,244	1,244	1,244	1,244
62	Demand Response 2	Business, Industrial	2010	Final	0	0	0	0	3,963	0	0	0
63	Demand Response 3	Business, Industrial	2010	Final	0	0	0	0	140	0	0	0
64	Loblaw & York Region Demand Response	Business, Industrial	2010	Final	0	0	0	0	0	0	0	0
65	LDC Custom - Hydro Ottawa - Small Commercial Di	Consumer	2010	Final	0	0	0	0	0	0	0	0
2006 Subtotal					**10,203**	**10,203**	**10,203**	**10,203**	**1,772**	**1,772**	**1,621**	**1,621**
2007 Subtotal					**0**	**11,722**	**8,953**	**8,610**	**8,610**	**8,608**	**4,980**	**4,980**
2008 Subtotal					**0**	**0**	**20,381**	**18,544**	**18,532**	**18,532**	**18,037**	**18,034**
2009 Subtotal					**0**	**0**	**0**	**20,905**	**18,663**	**18,663**	**18,653**	**18,342**
2010 Subtotal					**0**	**0**	**0**	**0**	**18,171**	**14,002**	**13,987**	**13,981**
Overall Total					**10,203**	**21,924**	**39,537**	**58,262**	**65,748**	**61,577**	**57,277**	**56,959**

Gross Summer Peak Demand Savings (MW)

#	Initiative Name	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	Secondary Refrigerator Retirement Pilot	Consumer	2006	Final	0.038	0.038	0.038	0.038	0.038	0.038	0.000	0.000
2	Cool & Hot Savings Rebate	Consumer	2006	Final	0.420	0.420	0.420	0.420	0.420	0.420	0.420	0.420
3	Every Kilowatt Counts	Consumer	2006	Final	0.127	0.127	0.127	0.127	0.127	0.127	0.127	0.127
4	Demand Response 1	Business, Industrial	2006	Final	7.633	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	Loblaw & York Region Demand Response	Business, Industrial	2006	Final	0.374	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	Great Refrigerator Roundup	Consumer	2007	Final	0.000	0.149	0.149	0.149	0.149	0.134	0.134	0.134
7	Cool & Hot Savings Rebate	Consumer	2007	Final	0.000	0.831	0.831	0.831	0.831	0.831	0.635	0.635
8	Every Kilowatt Counts	Consumer	2007	Final	0.000	0.199	0.176	0.176	0.176	0.176	0.176	0.176
9	***peaksaver®***	Consumer, Business	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	Summer Savings	Consumer	2007	Final	0.000	15.290	4.560	2.196	2.196	2.196	2.196	2.196
11	Aboriginal	Consumer	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	Affordable Housing Pilot	Consumer Low-Income	2007	Final	0.000	0.005	0.005	0.005	0.005	0.005	0.005	0.005
13	Social Housing Pilot	Consumer Low-Income	2007	Final	0.000	0.038	0.038	0.038	0.038	0.038	0.038	0.038
14	Energy Efficiency Assistance for Houses Pilot	Consumer Low-Income	2007	Final	0.000	0.003	0.003	0.003	0.003	0.003	0.003	0.003
15	Electricity Retrofit Incentive	Business	2007	Final	0.000	1.392	1.392	1.392	1.392	1.392	0.000	0.000
16	Toronto Comprehensive	Business	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17	Demand Response 1	Business, Industrial	2007	Final	0.000	8.634	0.000	0.000	0.000	0.000	0.000	0.000
18	Loblaw & York Region Demand Response	Business, Industrial	2007	Final	0.000	0.718	0.000	0.000	0.000	0.000	0.000	0.000
19	Renewable Energy Standard Offer	Consumer, Business, Industrial	2007	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20	Great Refrigerator Roundup	Consumer	2008	Final	0.000	0.000	0.244	0.244	0.244	0.244	0.230	0.230
21	Cool Savings Rebate	Consumer	2008	Final	0.000	0.000	0.709	0.709	0.709	0.709	0.709	0.709
22	Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0.000	0.000	0.427	0.405	0.405	0.405	0.364	0.364
23	***peaksaver®***	Consumer, Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	Summer Sweepstakes	Consumer	2008	Final	0.000	0.000	0.930	0.533	0.533	0.533	0.533	0.533
25	Electricity Retrofit Incentive	Consumer, Business	2008	Final	0.000	0.000	3.511	3.511	3.511	3.511	3.511	3.511
26	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
27	High Performance New Construction	Business	2008	Final	0.000	0.000	0.013	0.013	0.013	0.013	0.013	0.013
28	Power Savings Blitz	Business	2008	Final	0.000	0.000	0.003	0.003	0.001	0.001	0.001	0.001
29	Demand Response 1	Business, Industrial	2008	Final	0.000	0.000	11.893	0.000	0.000	0.000	0.000	0.000
30	Demand Response 3	Business, Industrial	2008	Final	0.000	0.000	2.300	0.000	0.000	0.000	0.000	0.000
31	Loblaw & York Region Demand Response	Business, Industrial	2008	Final	0.000	0.000	0.790	0.000	0.000	0.000	0.000	0.000
32	Renewable Energy Standard Offer	Consumer, Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
33	Other Customer Based Generation	Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
34	LDC Custom - Hydro One Networks Inc. - Double R	Business, Industrial	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
35	Great Refrigerator Roundup	Consumer	2009	Final	0.000	0.000	0.000	0.362	0.362	0.362	0.340	0.241
36	Cool Savings Rebate	Consumer	2009	Final	0.000	0.000	0.000	1.172	1.172	1.172	1.170	1.169
37	Every Kilowatt Counts Power Savings Event	Consumer	2009	Final	0.000	0.000	0.000	0.374	0.359	0.359	0.359	0.358
38	***peaksaver®***	Consumer, Business	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
39	Electricity Retrofit Incentive	Consumer, Business	2009	Final	0.000	0.000	0.000	2.444	2.444	2.444	2.444	2.444
40	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
41	High Performance New Construction	Business	2009	Final	0.000	0.000	0.000	0.147	0.147	0.147	0.147	0.147
42	Power Savings Blitz	Business	2009	Final	0.000	0.000	0.000	0.880	0.880	0.880	0.880	0.880
43	Multi-Family Energy Efficiency Rebates	Consumer, Consumer Low-Income	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
44	Demand Response 1	Business, Industrial	2009	Final	0.000	0.000	0.000	4.648	0.000	0.000	0.000	0.000
45	Demand Response 2	Business, Industrial	2009	Final	0.000	0.000	0.000	3.156	0.000	0.000	0.000	0.000
46	Demand Response 3	Business, Industrial	2009	Final	0.000	0.000	0.000	4.508	0.000	0.000	0.000	0.000
47	Loblaw & York Region Demand Response	Business, Industrial	2009	Final	0.000	0.000	0.000	0.775	0.000	0.000	0.000	0.000
48	LDC Custom - Thunder Bay Hydro - Phantom Load	Consumer	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
49	LDC Custom - Toronto Hydro - Summer Challenge	Consumer	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
50	LDC Custom - PowerStream - Data Centers	Business	2009	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
51	Toronto Comprehensive Adjustment	Consumer, Business	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
52	LDC Custom - Hydro One Networks Inc. - Double R	Business, Industrial	2008	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
53	Great Refrigerator Roundup	Consumer	2010	Final	0.000	0.000	0.000	0.000	0.395	0.395	0.395	0.379
54	Cool Savings Rebate	Consumer	2010	Final	0.000	0.000	0.000	0.000	1.826	1.826	1.826	1.826
55	Every Kilowatt Counts Power Savings Event	Consumer	2010	Final	0.000	0.000	0.000	0.000	0.112	0.112	0.112	0.112
56	***peaksaver®***	Consumer, Business	2010	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
57	Electricity Retrofit Incentive	Consumer, Business	2010	Final	0.000	0.000	0.000	0.000	0.480	0.480	0.480	0.480
58	Toronto Comprehensive	Consumer, Consumer Low-Income, Busine	2010	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
59	High Performance New Construction	Business	2010	Final	0.000	0.000	0.000	0.000	0.525	0.525	0.525	0.525
60	Power Savings Blitz	Business	2010	Final	0.000	0.000	0.000	0.000	2.464	2.464	2.464	2.464
61	Multi-Family Energy Efficiency Rebates	Consumer, Consumer Low-Income	2010	Final	0.000	0.000	0.000	0.000	0.138	0.138	0.138	0.138
62	Demand Response 2	Business, Industrial	2010	Final	0.000	0.000	0.000	0.000	3.391	0.000	0.000	0.000
63	Demand Response 3	Business, Industrial	2010	Final	0.000	0.000	0.000	0.000	7.171	0.000	0.000	0.000
64	Loblaw & York Region Demand Response	Business, Industrial	2010	Final	0.000	0.000	0.000	0.000	0.832	0.000	0.000	0.000
65	LDC Custom - Hydro Ottawa - Small Commercial D	Consumer	2010	Final	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2006 Subtotal					**8.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.55**	**0.55**
2007 Subtotal					**0.00**	**27.26**	**7.15**	**4.79**	**4.79**	**4.77**	**3.19**	**3.19**
2008 Subtotal					**0.00**	**0.00**	**20.82**	**5.42**	**5.42**	**5.42**	**5.36**	**5.36**
2009 Subtotal					**0.00**	**0.00**	**0.00**	**18.47**	**5.36**	**5.36**	**5.34**	**5.24**
2010 Subtotal					**0.00**	**0.00**	**0.00**	**0.00**	**17.33**	**5.94**	**5.94**	**5.92**
Overall Total					**8.59**	**27.84**	**28.56**	**29.26**	**33.49**	**22.08**	**20.38**	**20.26**

Appendix C: London Hydro 2013 LRAM for 2011 CDM Programs Recoveries Rate Application.

Response to Board Staff IR # 47: LRAMVA 2011 OPA CDM Programs

2013 Lost Revenue Adjustment Mechanism ("LRAM") for 2011 CDM Programs Recoveries Rate Application

1. Introduction

On May 31, 2004, the Minister of Energy granted approval to all distributors in Ontario to apply to the Ontario Energy Board (the "Board") for an increase in their 2005 rates by way of the third installment of their incremental market adjusted revenue requirement ("MARR"). This approval was conditional upon a commitment to reinvest in conservation and demand management ("CDM") an equivalent of one year's return. Consequently, in 2005 distributors, including London Hydro, brought forward, and the Board approved, $163 million in CDM funding for distributors, an amount related to the third tranche of their MARR.

In 2006 and through to 2012, London Hydro has received CDM funding from the Ontario Power Authority (the "OPA"). London Hydro's significant commitment to both CDM Programs and the achieving for customer efficiency in the use of energy London Hydro combined with the partnership of the OPA, has resulted in 2011 OPA verified 2011 to 2014 net cumulative energy savings of 84.04 gWh (representing 53.65% of London Hydro's 2011 to 2014 cumulative CDM energy target).

Previous to London Hydro's 2012 IRM rate application filing (EB-2011-0181), London Hydro had not applied for any recoveries for lost distribution revenues for either due to CDM programs funded from 3rd tranche MARR funding, or 2006, 2007, and 2008 CDM programs that were funded by the OPA. In Board's Decision and Order of London Hydro's 2012 IRM rate application (EB-2011-0181), it is stated, "*The Board approves an LRAM recovery of $152,652.49 representing lost revenues from 2010 CDM programs in the year 2010, as London was under IRM in this year and London has not otherwise received LRAM compensation for this year*". The Board further stated approval of, "*a one*

year disposition period for the LRAM recovery of $152,652.49". The approved rate rider for lost revenue adjustment mechanism ("LRAM") recovery is effective to April 30, 2013, as evidence in London Hydro's Tariff of Rates and Charges (Effective Date May 1, 2012).

In preparing this recovery of LRAM, London Hydro has followed the *Board's Guidelines for Electricity Distributor Conservation and Demand Management issued on March 28, 2008* (the "CDM Guidelines", EB-2008-0037). The Ontario Energy Board CDM Guidelines provide information on the Board's policies relating to Conservation and Demand Management activities undertaken by electricity distributors in Ontario, including the review and approval of claims for the LRAM recovery associated with distributors' CDM activities. Further, guidance was obtained by relying on the September 22, 2009 Decision and Order related to Toronto Hydro-Electric System Limited LRAM/ SSM application (the "Toronto Hydro 2007 Decision") granting approval and recovery of amount related to CDM activated in 2007 (EB-2008-0401).

The Board updated the CDM Guidelines on April 26, 2012 and the filing requirements on June 28, 2012 for LRAM claims for pre-2011 CDM activities. In Section 13.6 of the Board Guidelines states, " *The Board expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service".*

London Hydro's last approved Cost of Service Rate Application was for 2009 (EB-2008-0235).

In London hydro's response to Board staff intervenor questions, and in particular Question # 39, London Hydro has applied for recoveries for 2011 and 2012 lost

distribution revenues due to persistent 2010 CDM programs funded by the OPA. The amount that the Applicant seeks to recover through volumetric rate riders totals a
LRAM amount of $266,877.56, including carrying costs.

London Hydro, in response to Board staff intervenor questions, and in particular Question # 47, London Hydro is applying both for recoveries for 2011 lost distribution revenues due to 2011 CDM programs funded by the OPA, and recoveries for 2012 lost distribution revenues due to persistent 2011 CDM programs funded by the OPA. . The amount that the Applicant seeks to recover through volumetric rate riders totals a
LRAM amount of $176,092, including carrying costs.

Pre-2011 Programs completed in 2011:

It should be clarified that London Hydro applied for LRAM for CDM Program Results as contained in the 2011 CDM OPA report (file as Excel document and identified as “LondonHydro_ Copy of 2011_Final_Annual_Report_Data_CDM_OPAPrograms_20130108”). This includes results related to Pre-2011 Programs completed in 2011 (as reflected in the table below).

Table 5: Summarized Program Results

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Pre-2011 Programs completed in 2011											
22	Electricity Retrofit Incentive Program	94%	95%	2,288	16,207,519	60%	60%	1,359	9,726,531	1,359	38,906,125
23	High Performance New Construction	100%	100%	337	1,731,809	50%	50%	169	865,905	169	3,463,618
24	Toronto Comprehensive	-	-	0	0	-	-	0	0	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0	0	0

Assumes demand response resources have a persistence of 1 year

London Hydro took into consideration that these results are 2010 carry-over projects and are those approved under the OPA 2010 rules and incentive levels, but actually carried out in 2011. It would be inappropriate for London Hydro to record these program savings results into the 2010 LRAM application filing. Therefore these savings are not included in this 2010 LRAM filing, but included in the 2011 LRAM application filing.

2. 2011 OPA Programs

The OPA has provided London Hydro with the 2011 verified results for all OPA funded programs for 2010 and 2011. Details are provided Appendix A: OPA – 2011 Final Annual CDM Results London Hydro Inc.

The Board's Guidelines states "The LRAM applies to programs implemented by the distributor, within its licensed service area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party" (Pg. 18, Board's Guidelines for Electricity Distributor Conservation and Demand Management issued on March 28, 2008).

The CDM programs that London Hydro delivered through the OPA in 2011 in the London Hydro service territory were:

- Appliance Retirement
- Appliance Exchange,
- HVAC Incentives,
- Conservation Instant Coupon Booklet,
- Bi-annual Retailer Event,
- Efficiency Equipment Replacement,
- Direct Install Lighting,
- Demand Response 3 Programs.

An OPA Province-Wide Evaluation Findings is provided below:

Table 3: OPA Province-Wide Evaluation Findings

#	*Initiative*	*OPA Province-Wide Key Evaluation Findings*
Consumer Program		
1	Appliance Retirement	* Overall participation continues to decline year over year * Participation declined 17% from 2010 (from over 67,000 units in 201 to over 56,000 units in 2011) * 97% of net resource savings achieved through the home pick-up stream * Measure Breakdown: 66% refrigerators, 30% freezers, 4% Dehumidifiers and window air conditioners * 3% of net resource savings achieved through the Retailer pick-up stream * Measure Breakdown: 90% refrigerators, 10% freezers * Net-to-Gross ratio for the initiative was 50% * Measure-level free ridership ranges from 82% for the retailer pick-up stream to 49% for the home pick-up stream * Measure-level spillover ranges from 3.7% for the retailer pick-up stream to 1.7% for the home pick-up stream
2	Appliance Exchange	* Overall eligible units exchanged declined by 36% from 2010 (from over 5,700 units in 2010 to over 3,600 units in 2011) * Measure Breakdown: 75% window air conditioners, 25% dehumidifie * Dehumidifiers and window air conditioners contributed almost equally to the net energy savings achieved * Dehumidifiers provide more than three times the energy savings per unit than window air conditioners * Window air conditioners contributed to 64% of the net peak demand savings achieved * Approximately 96% of consumers reported having replaced their exchanged units (as opposed to retiring the unit) * Net-to-Gross ratio for the initiative is consistent with previous evaluations (51.5%)
3	HVAC Incentives	* Total air conditioner and furnace installations increased by 14% (from over 95,800 units in 2010 to over 111,500 units in 2011) * Measure Breakdown: 64% furnaces, 10% tier 1 air conditioners (SEER 14.5) and 26% tier 2 air conditioners (SEER 15) * Measure breakdown did not change from 2010 to 2011 * The HVAC Incentives initiative continues to deliver the majority of both the energy (45%) and demand (83%) savings in the consumer program * Furnaces accounted for over 91% of energy savings achieved for this

		initiative * Net-to-Gross ratio for the initiative was 17% higher than 2010 (from 43% in 2010 to 60% in 2011) * Increase due in part to the removal of programmable thermostats from the program, and an increase in the net-to-gross ratio for both Furnaces and Tier 2 air conditioners (SEER 15)
4	Conservation Instant Coupon Booklet	* Customers redeemed nearly 210,000 coupons, translating to nearly 560,000 products * Majority of coupons redeemed were downloadable (~40%) or LDC-branded (~35%) * Majority of coupons redeemed were for multi-packs of standard spir CFLs (37%), followed by multi-packs of specialty CFLs (17%) * Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted averag of 2009 and 2010 evaluation findings * Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed
5	Bi-Annual Retailer Event	* Customers redeemed nearly 370,000 coupons, translating to over 870,000 products * Majority of coupons redeemed were for multi-packs of standard spir CFLs (49%), followed by multi-packs of specialty CFLs (16%) * Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted averag of 2009 and 2010 evaluation findings * Standard CFLs and heavy duty outdoor timers were reintroduced to the initiative in 2011 and contributed more than 64% of the initiative 2011 net annual energy savings * While the volume of coupons redeemed for heavy duty outdoor timers was relatively small (less than 1%), the measure accounted for 10% of net annual savings due to high per unit savings * Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed.
Business Program		
9	Efficiency: Equipment Replacement	* Gross verified energy savings were boosted by lighting projects in the prescriptive and custom measure tracks * Lighting projects overall were determined to have a realization rate of 112%; 116% whe including interactive energy changes * On average, the evaluation found high realization rates as a result of both longer operating hours and larger wattage reductions than initia assumptions * Low realization rates for engineered lighting projects due to overstated operating hour assumptions * Custom non-lighting projects suffered from process issues such as: the absence of required M&V plans, the use of inappropriate assumptions , and the lack of adherence the M&V plan * The final realization rate for summer peak demand was 94% * 84% was a result of different methodologies used to calculate peak demand savings

		* 10% due to the benefits from reduced air conditioning load in lightin retrofits * Overall net-to-gross ratios in the low 70's represent an improvement over the 2009 and 2010 ERIP program where net-to-gross ratios were in the low 60's and low 50's, respectively. Strict eligibility requirements and improvements in the pre-approval process contribute to the improvement in net-to-gross ratios
10	Direct Install Lighting	* Though overall performance is above expectations, participation continues to decline year over year as the initiative reaches maturity * 70% of province-wide resource savings persist to 2014 * Over 35% of the projects for 2011 included at least one CFL measure * Resource savings from CFLs in the commercial sector only persist for the industry standard of 3 years * Since 2009 the overall realization rate for this program has improved * 2011 evaluation recorded the highest energy realization rate to date at 89.5% * The hours of use values were held constant from the 2010 evaluation and continue to be the main driver of energy realization rate * Lights installed in "as needed" areas (e.g., bathrooms, storage areas) were determined to have very low realization rates due to the difference in actual energy saved vs. reported savings
15	Demand Response 3 (part of the Industrial program schedule)	* See Demand Response 3 (#20)
Industrial Program		
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	* See Efficiency: Equipment Replacement (#9)
20	Demand Response 3	* Program performance for Tier 1 customers increased with DR-3 participants providing 75% of contracted MW for both sectors Program continues to diversify but still remains heavily concentrated with less than 5% the contributors accounting for the majority (~60%) of the load reductions. By increasing the number of contributors in each settlement account and implementation of the new baseline methodology the performance of the program is expected to increase

In Table 1, OPA CDM Load Impacts (2011), reflects the OPA Programs for which London Hydro is seeking a LRAM recovery in 2013. The table indicates the kWh and Kw impacts (both in gross and net of free riders) for 2011.

TABLE 1 – OPA CDM Program Load Impacts (2011)

London Hydro Inc.

OPA CDM Program Load Impacts (2011)

2011 Data from OPA Verfied Results
see Tab 1- OPA CDM Savings

*London Hydro is not requesting LRAM /SSM for Programs in 2006, 2007, and 2008. Programs in 2009 were also not included

		2011		2011			2012		2012		TOTAL		TOTAL	
		NET		GROSS			NET		GROSS		NET		GROSS	
Class/ Program	Year Program Implimented	kWh	Kw	kWh	Kw		kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw
RESIDENTIAL														
Appliance Retirement	2011	1,002,610	167.0	1,967,720	350.0		1,002,610	167.0	2,471,000	395.0	2,005,220	334.0	4,438,720	745.0
Appliance Exchange	2011	15,910	12.0	30,871	24.0		15,910	12.0	2,855,000	1,826.0	31,820	24.0	2,885,871	1,850.0
HVAC Incentives	2011	1,901,868	1,052.0	3,173,112	1,739.0		1,901,868	1,052.0	1,159,000	112.0	3,803,736	2,104.0	4,332,112	1,851.0
Conservative Instant Coupon Booklet	2011	512,644	32.0	465,107	28.0		512,644	32.0	1,159,000	112.0	1,025,288	64.0	1,624,107	140.0
Bi-Annual Retailer Event	2011	802,521	46.0	734,572	41.0		802,521	46.0	1,159,000	112.0	1,605,042	92.0	1,893,572	153.0
Residential Total		4,235,553	1,309.0	6,371,382	2,182.0		4,235,553	1,309.0	8,803,000	2,557.0	8,471,106	2,618.0	15,174,382	4,739.0
General Service < 50 kW														
OPA Energy Retrofit Incentive Program (ERIP)	2010	797,576	111.4	1,329,017	187.6		797,576	111.4	1,329,017	187.6	1,595,151	222.9	2,658,033	375.2
High Performance New Construction*	2010	865,905	169.0	1,731,809	337.0		865,905	169.0	1,731,809	337.0	1,731,810	338.0	3,463,618	674.0
Efficiency Equipment Replacement	2011	493,355	95	657,805	130		493,355	95	657,805	129.6	986,710	190.6	1,315,610	259.1
Direct Install Lighting	2011	145,929	56.0	157,160	52.0		145,929	368.0	1,198,000	525.0	291,858	424.0	1,355,160	577.0
Demand Response 3	2011	19,012	485.0	19,012	642.0		0	0.0	0	0.0	19,012	485.0	19,012	642.0
Total General Service < 50 kW		2,321,777	917	3,894,802	1,348		2,302,765	744	4,916,630	1,179.2	4,624,542	1,660.4	8,811,433	2,527.4
General Service 50 kW to 4,999 kW														
OPA Energy Retrofit Incentive Program (ERIP)	2010	8,928,955	1,247.6	14,878,502	2,100.4		8,928,955	1,247.6	14,878,502	2,100.4	17,857,911	2,495.1	29,757,005	4,200.8
Efficiency Equipment Replacement	2011	5,523,172	1,066.7	7,364,206	1,450.4		5,523,172	1,066.7	7,364,206	1,450.4	11,046,344	2,133.4	14,728,412	2,900.9
Demand Response 3	2011	125,454	2,137.0	125,454	2,536.0		0	0.0	0	0.0	125,454	0.0	125,454	0.0
Total General Service 50 to 4,999 kW		14,577,581	4,451.3	22,368,163	6,087		14,452,127	2,314	22,242,709	3,550.8	29,029,708	4,628.6	44,610,871	7,101.6
Total Load Impacts from OPA programs		21,134,911	6,677	32,634,347	9,617		20,990,445	4,367	35,962,339	7,287	42,125,356	8,907	68,596,686	14,368

Although many of the OPA energy conservation and demand management programs are specific to a rate class, the Electricity Retrofit Incentive Programs (ERIP, and its successor the Efficiency Equipment Replacement Program) does span several customer classes, namely general service less than 50 kW, and general service greater than 50 kW.

Reviewing our records and the information as submitted to the OPA, for ERIP projects carried within our service territory during 2010, the division of gross kW reductions amongst customer classes was:

Table 2, 2010 ERIP Gross Demand Reduction (within London)

Customer Classification	Gross kW Demand Reduction	Percentage
General Service Less Than 50 kW	316	8.2%
General Service Greater Than 50 kW	3,554	91.7%
Large User	0	0%
Total:	**3,874**	**99.9%**

**For the purposes of reflecting 100% totals for the above allocations, the 0.1% balance will be allocated to general service greater than 50 kW.*

TABLE 2 – kWh and Kw Allocation of ERIP Program to Customer Classes for 2011

ERIP ALLOCATION:		2011		2011		2012		2012	
From OPA Verified Results (see Tab ERIP Savings)		NET		GROSS		NET		GROSS	
** Used 2011 OPA verified results as proxy for 2012.		6,016,527	1,162	8,022,011	0.0				
Allocation of Retrofit kWh (GS 50 and Kw Demand)	2010	6,016,527	1,162.0	8,022,011	-				
GS < 50	8.2%	493,355	95.3	657,805	-				
GS 1,000 to 4,999 kW	91.8%	5,523,172	1,066.7	7,364,206	-				
		6,016,527	1,162.0	8,022,011	-				
	2010	-		-		6,016,527	1,162.0	8,022,011	-
GS < 50	8.2%	-	-	-	-	493,355	95.3	657,805	-
GS 1,000 to 4,999 kW	91.8%	-	-	-	-	5,523,172	1,066.7	7,364,206	-
						6,016,527	1,162.0	8,022,011	-

3. Forgone Revenues

For the 2013 LRAM resulting from actual 2011 OPA programs, London Hydro has reflected the OPA confirmed energy savings by OPA program and by customer class and valued these savings using the appropriate variable distribution charge (per kWh or kW, as applicable), and not including any Regulatory Asset Recovery rate rider.

TABLE 3 – Forgone Revenue by Program and Class

Forgone Revenue by Program and Class

*London Hydro is not requesting LRAM /SSM for Programs in 2006, 2007, and 2008. Programs in 2009 were also not included

		2011				2012				Total Revenue
Class/ Program	Year Program Implimented	Load Impact	kWh or kW	Rate per Unit	Revenue	Load Impact	kWh or kW	Rate per Unit	Revenue	
RESIDENTIAL										
Appliance Retirement	2011	1,002,610	kWh	$ 0.0142	$ 14,237.06	1,002,610	kWh	$ 0.0143	$ 14,337.32	$ 28,574.39
Appliance Exchange	2011	15,910	kWh	$ 0.0142	$ 225.92	15,910	kWh	$ 0.0143	$ 227.51	$ 453.44
HVAC Incentives	2011	1,901,868	kWh	$ 0.0142	$ 27,006.53	1,901,868	kWh	$ 0.0143	$ 27,196.71	$ 54,203.24
Conservative Instant Coupon Booklet	2011	512,644	kWh	$ 0.0142	$ 7,279.54	512,644	kWh	$ 0.0143	$ 7,330.81	$ 14,610.35
Bi-Annual Retailer Event	2011	802,521	kWh	$ 0.0142	$ 11,395.80	802,521	kWh	$ 0.0143	$ 11,476.05	$ 22,871.85
Residential Total		**4,235,553**			**$ 60,144.85**	**4,235,553**			**$ 60,568.41**	**$ 120,713.26**
General Service < 50 kW										
OPA Energy Retrofit Incentive Program (ERIP)	2010	797,576	kWh	$ 0.0091	$ 7,257.94	797,576	kWh	$ 0.0092	$ 7,337.69	$ 14,595.63
High Performance New Construction*	2010	865,905	kWh	$ 0.0091	$ 7,879.74	865,905	kWh	$ 0.0092	$ 7,966.33	$ 15,846.06
Efficiency Equipment Replacement	2011	493,355	kWh	$ 0.0091	$ 4,489.53	493,355	kWh	$ 0.0092	$ 4,538.87	$ 9,028.40
Direct Install Lighting	2011	145,929	kWh	$ 0.0091	$ 1,327.95	145,929	kWh	$ 0.0092	$ 1,342.55	$ 2,670.50
Demand Response 3	2011	19,012	kWh	$ 0.0091	$ 173.01	0	kWh	$ 0.0092	$ -	$ 173.01
	2011	0	kWh	$ 0.0091	$ -	0	kWh	$ 0.0092	$ -	$ -
Total General Service < 50 kW		**2,321,777**			**$ 21,128.17**	**2,302,765**			**$ 21,185.44**	**$ 42,313.60**
General Service 50 kW to 4,999 kW										
OPA Energy Retrofit Incentive Program (ERIP)	2010	1,247.6	kW	$ 1.6081	$ 2,006.20	1,248	kW	$ 1.6223	$ 2,023.92	$ 4,030.12
Efficiency Equipment Replacement	2011	1,066.7	kW	$ 1.6081	$ 1,715.39	1,067	kW	$ 1.6223	$ 1,730.53	$ 3,445.92
Demand Response 3	2011	2,137	kW	$ 1.6081	$ 3,436.51	0	kW	$ 1.6223	$ -	$ 3,436.51
Total General Service 50 to 4,999 kW		**4,451**			**$ 7,158.10**	**2,314**			**$ 3,754.45**	**$ 10,912.55**
Total Forgone Revenue OPA programs		**6,561,781**			**$ 88,431.12**	**6,540,632**			**$ 85,508.30**	**$ 173,939.42**

4. Carrying Charges

In the Toronto Hydro Decision, the Board found that Toronto Hydro was entitled to carrying charges on the LRAM balances. London Hydro has calculated carrying charges as follows: interest has been applied to the ending balance of the annual LRAM for all of
2011 and 2012.The calculation of the carrying costs used the Board's prescribed interest rates for Q1 2011 – Q1 2013, as shown in Table 4.

Table 4 – Board's Prescribed Interest Rates and Calculated Interest

	Q1 2012	Q2 2012	Q3 2012	Q4 2012	4 Months to April 30, 2013	Total
%	1.47	1.47	1.47	1.47	1.47	
Residential ($)	$ 221	$ 221	$ 221	$ 221	$ 591	$ 1,475.62
GS < 50 kW ($)	$ 78	$ 78	$ 78	$ 78	$ 207	$ 517.92
GS 50 to 4,999 kW ($)	$ 26	$ 26	$ 26	$ 26	$ 53	$ 158.70

5. Calculation of Rate Rider

The amount of relief request for LRAM is an amount of $139,467.60, plus $1731.31 carrying charges.

The LRAM rate rider being applied, as calculated in Table 5 – LRAM Rate Riders, includes LRAM as reflected in Table 3 – Forgone Revenue by Program by Class, and Carrying Charges as reflected in Table 4 – Board's Prescribe Interest Rates and Calculated Interest. The Billing Determines is actual distribution energy quantities (kWh or kW) for 2011.

Table 5 – LRAM Rate Riders for 2013

Class	Units	LRAM	Carrying Charges	Total	2011 Billing Determines	Rate Rider
Residential	kWh	$ 120,713	$ 1,476	$ 122,190	1,128,904,736	$ 0.00011
GS < 50 kW	kWh	$ 42,314	$ 518	$ 42,832	408,115,902	$ 0.00010
GS 50 to 4,999 kW	kW	$ 10,913	$ 159	$ 11,071	3,944,476	$ 0.00281
Totals		$ 173,939	$ 2,152	$ 176,092		

Billing Deteminates used 2011 Distribution Energy Quantities (Actual)

London Hydro is requesting a volumetric LRAM specific rate rider be established to collect the total recovery amount. The proposed rate rider is over a one-year period, effective May 1, 2013.

Therefore, London Hydro is requesting approval for a LRAM volumetric rate rider of $0.00011/kWh for the Residential class and $0.0001/kWh for General Service > 50 kW Class, and $0.00281/kW for General Service 50 to 4,999 kW Class.

6. Third party Verification

Section 7.5 of the Board's Guidelines requires that distributors should engage an independent third party to review the program evaluations prepared for the purposes of

LRAM claims filed with the Board. The Guidelines state “This independent third party review applies to LRAM and SSM claims made in relation to programs funded in 2007 and beyond”, but goes on to say “The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient. For programs funded by the OPA, it will be the role of the third party to:

- Verify the participation levels, and,
- Confirm that input assumptions are those used by the OPA“

Appendix A: OPA – 2011 Final Annual CDM Results London Hydro

Table 5: Summarized Program Results						
Program	Gross Savings		Net Savings		Contribution to Targets	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	2,182	6,371,383	1,309	4,235,553	1,288	16,924,158
Business Program Total	2,103	7,211,326	1,575	5,425,294	1,076	21,596,043
Industrial Program Total	2,708	1,112,311	2,265	881,628	127	3,147,173
Home Assistance Program Total	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total	2,625	17,939,328	1,528	10,592,436	1,528	42,369,743
Total OPA Contracted Province-Wide CDM Programs	**9,618**	**32,634,347**	**6,677**	**21,134,911**	**4,020**	**84,037,117**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program											
1	Appliance Retirement	100%	100%	350	1,967,720	49%	52%	167	1,002,610	153	3,998,531
2	Appliance Exchange	100%	100%	24	30,871	52%	52%	12	15,910	5	57,495
3	HVAC Incentives	100%	100%	1,739	3,173,112	61%	60%	1,052	1,901,868	1,052	7,607,473
4	Conservation Instant Coupon Booklet	100%	100%	28	465,107	114%	111%	32	512,644	32	2,050,576
5	Bi-Annual Retailer Event	100%	100%	41	734,572	113%	110%	46	802,521	46	3,210,084
6	Retailer Co-op	-	-	0	0	-	-	0	0	0	0
7	Residential Demand Response	0%	0%	0	0	-	-	0	0	0	0
8	Residential New Construction	-	-	0	0	-	-	0	0	0	0
Business Program											
9	Efficiency: Equipment Replacement	92%	123%	1,408	7,035,154	73%	75%	1,034	5,260,353	1,024	21,005,761
10	Direct Install Lighting	108%	90%	52	157,160	93%	93%	56	145,929	52	571,271
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0	0	0
12	New Construction and Major Renovation Incentive	-	-	0	0	-	-	0	0	0	0
13	Energy Audit	-	-	0	0	-	-	0	0	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	0	0	-	-	0	0	0	0
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	642	19,012	n/a	n/a	485	19,012	0	19,012
Industrial Program											
16	Process & System Upgrades	-	-	0	0	-	-	0	0	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0	0	0
18	Energy Manager	-	-	0	0	-	-	0	0	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	92%	131%	172	986,857	74%	77%	128	756,174	127	3,021,719
20	Demand Response 3	84%	100%	2,536	125,454	n/a	n/a	2,137	125,454	0	125,454
Home Assistance Program											
21	Home Assistance Program	-	-	0	0	-	-	0	0	0	0
Pre-2011 Programs completed in 2011											
22	Electricity Retrofit Incentive Program	94%	95%	2,288	16,207,519	60%	60%	1,359	9,726,531	1,359	38,906,125
23	High Performance New Construction	100%	100%	337	1,731,809	50%	50%	169	865,905	169	3,463,618
24	Toronto Comprehensive	-	-	0	0	-	-	0	0	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0	0	0

APPENDIX D – RSVA Commodity Variance Accounts – Unbilled Energy Calculation Review 1588 RSVA Power and RSVA Power Sub-account Global Adjustment

(Response to Board Staff IR #52: Account 1588)

RSVA Commodity Variance Accounts – Unbilled Energy Calculation Review 1588 RSVA Power and RSVA Power Sub-account Global Adjustment background information.

During the 2012 year, it was identified that there may be an issue with the RRR reporting of the RSVA Power and the RSVA Power Sub-account Global adjustment ("RSVA-GA") unbilled energy calculations due to the accruals utilized in the month end reporting process and as a result an extensive review has taken place.

After the completion of this review it has been determined that the suspicion of the incorrect reporting has been confirmed for the RSVA-GA balances although the RSVA Power balances are determined to be correct.

Background process:

Cost of Power – power purchases from the IESO (wholesale kWh)

The IESO invoices the distributor the power consumed in the trade month. This invoice is received after the month end, and is accrued into the respective trade month to reflect the cost of power in the appropriate period.
The charges are for the current trade month consumption (wholesale purchases) at current trade month prices (charge types 101, 148), adjusted with the RPP settlement amount (charge type 142) for the trade month. The RPP settlement amount is calculated and submitted by the distributor to the IESO before the invoice is issued.

The formula to calculate RPP settlement amount:

*Current trade month usage RPP portion kWh * ($RPP/kWh – ($HOEP/kWh + $GA/kWh)*

Cost of Power for trade month		**$(000)**
Energy Charge type 101	$	10,800
Global Adjustment CT 148	$	11,400
RPP Settlement CT 142	$	300
	$	**22,500**

1588 RSVA Power – Sub-account Global Adjustment:

The Power Sub-account Global Adjustment account is used to record the difference between the global adjustment amount billed to non-RPP consumers and the global adjustment charge to London Hydro for non-RPP consumers.

Since this account is applicable to non-RPP customers only, it should be cleared to non-RPP customers only.

What is the RSVA Power sub-account Global Adjustment consists of?

Historically, here is an example of the entries that would be recorded surrounding the RSVA GA account. Example:

			($000)	
during month	Amounts billed to customers		(6,700)	
	GA billed to Non-RPP customers only	(6,700)		
during month	Total payments to IESO		5,900	
	Paid IESO invoice - GA (charge types 146,147,148)	10,800		
	Fixed price adjustment: RPP kWh * $GA/kWh	(4,900)		
	Interest	2	2	
last day of month	Unbilled energy accrued		(4,600)	
	Non-RPP customers (unbilled kWh * $GA/kWh)	(4,600)		
last day of month	Accrued unpaid IESO invoice for trade month		6,200	
	Unpaid IESO invoice - GA (charge types 146,147,148)	11,400		
	Fixed price adjustment: RPP kWh * $GA/kWh	(5,200)		
last day of month	Fixed price energy credits on unbilled		(5,200)	
	Fixed price adjustment: RPP kWh * $GA/kWh	(5,200)		
first day of next month	Reversing Accrual of Unbilled Energy for prior month		4,600	These accruals net to zero after reversal
	Non-RPP customers (unbilled kWh * $GA/kWh)	4,600		
first day of next month	Reversing accrual for Unpaid IESO invoice		(6,200)	
	Global Adjustment (charge types 146,147,148)	(11,400)		
	Fixed price adjustment: RPP kWh * $GA/kWh	5,200		
first day of next month	Reversing prior month Fixed price energy credits on unbilled		5,200	
	Fixed price adjustment: RPP kWh * $GA/kWh	5,200		

London Hydro utilizes a prorated/accrual method to determine the unbilled quantities in the RSVA-GA calculation and therefore there is no outstanding portion to be submitted in future periods, (other than minor true-ups for prior periods). Therefore, the historical accrual using the unbilled kWh for global adjustment credit is not required (this is the accrual highlighted in red booked on the last day of the month in the above example).

Initially, the forward method was utilized by London Hydro in the calculation of the global adjustment fixed price credits, but the accrual method was implemented during 2010. From the implementation in 2010 forward the accrual entry based unbilled quantities should have no longer been recorded.

The disposition resulting from the 2012 IRM proceedings (EB-2012-0181) included the accrual for $3,802,961 credit. This was accrued in error and therefore the Global Adjustment Rate Rider currently in place is misaligned.

The disposition amount was:	$1,291,157 **credit** *plus carrying charges to April 30, 2012*
The disposition amount should have been:	$2,511,804 **debit** *plus carrying charges to April 30, 2012*
Adjustment required to-realign this disposition:	$3,802,961 **debit** *plus carrying charges*

1588 RSVA Power (excluding Global Adjustment):

The RSVA Power account is designed to capture variances due to billing timing differences, price and quantity differences, and line loss differences. The power variance should be cleared to all customers.

What is the RSVA Power Account consists of? Example

during month	Amounts billed to customers		(17,000)
	Energy billed to Non-RPP customers	(6,000)	
	Energy billed to RPP customers	(11,000)	
during month	Total payments to IESO (previous trade month invoice)		18,200
	Paid IESO invoice - energy (charge type 101)	12,800	
	Fixed price adjustment: RPP kWh * ($RPP/kWh - $HOEP/kWh)	5,400	
	Interest	(10)	(10)
last day of month	Accrue Unbilled Energy for trade month		(15,100)
	Non-RPP customers unbilled kWh * $HOEP/kWh	(5,060)	
	RPP customers unbilled kWh * $RPP/kWh	(10,040)	
last day of month	Accrue Unpaid IESO Invoice for trade month		16,300
	Energy (charge type 101)	10,800	
	Fixed price adjustment: RPP kWh * ($RPP/kWh - $HOEP/kWh)	5,500	
last day of month	Fixed price energy credits on unbilled		
	Fixed price adjustment: RPP kWh * ($RPP/kWh - $HOEP/kWh)	5,500	5,500
first day of next month	Reversing Accrual of Unbilled Energy from prior month		15,100
	Non-RPP customers (unbilled kWh * $HOEP/kWh)	5,060	
	RPP customers (unbilled kWh * $RPP/kWh)	10,040	
first day of next month	Reversing accrual for Unpaid IESO invoice		(16,300)
	Energy (charge type 101)	(10,800)	
	Fixed price adjustment: RPP kWh * ($RPP/kWh - $HOEP/kWh)	(5,500)	
first day of next month	Reversing prior month Fixed price energy credits on unbilled		(5,500)
	Fixed price adjustment: RPP kWh * ($RPP/kWh - $HOEP/kWh)	(5,500)	

These accruals net to zero after reversal

London Hydro has utilized the forward based methodology since the commencement of Form 1598. As a result of the forward methodology, there are amounts which have yet to be billed by the IESO for power consumed for fixed price customers.

The above illustration shows the accrued unpaid IESO invoice for the trade month including the fixed price debits applicable to RPP billings calculated on a forward basis. That is:

billed RPP kWh * ($RPP/kWh - $HOEP/kWh)

The unbilled portion of the energy price variance is added to the IESO invoice in the following period. The accrual entry for this amount is calculated using the formula of:

unbilled RPP kWh * ($RPP/kWh - $HOEP/kWh)

Based on the illustration above and after the completion of the comprehensive review, the accrual entry for the fixed price debits within 1588 RSVA Power account **is required** for the unbilled portion of energy to arrive at the same month-end results as the accrual method. The journal entries are:

dr 4705 Power Purchased	$5,400
cr 2205 Accounts Payable – Due to IESO	($5,400)

Fixed price energy debit/credit on unbilled amounts

dr 1588 RSVA Power	$5,400
cr 4705 Power Purchased	($5,400)

Close off power purchase to RSVA Account

The accrual entry estimates the amount to be submitted in the subsequent month for the usage within current trade month from 1588 RSVA Power account to Accounts Payable due to the IESO. This is a consequential result of employing the forward based method in calculating the RPP energy price variance.

All prior year RSVA Power reported balances up until the end of 2011 are correct including the balance disposed with the 2012 IRM proceedings (EB-2012-0181). No realignment is required for the Rate Rider including the RSVA Power disposition.

1588 RSVA Power Account recalculated

1588 RSVA Power Sub-Account Global Adjustment recalculated

1588 RSVA Power (excluding Global Adjustment) as filed and reconciled to RRR 2.1.7

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Debits	Total Net Accruals	Board Approved Disposition	Closing Balance	RRR 2.1.7	Variance	
2008 Year-end accrual for Fixed Price Credit reversing in 2009				1,187,000	1,187,000					
Year 2009	(3,015,389)	(66,735)	(3,908,474)	2,269,300	(1,639,174)	3,040,110	(1,681,188)	(1,681,188)	(0)	*Note 1.*
Year 2010	(1,681,188)	(44,119)	(390,197)	349,800	(40,397)	-	(1,765,703)	(1,765,703)	0	*Note 2.*
Year 2011	(1,765,703)	(111,746)	(4,479,632)	2,266,500	(2,213,132)	-	**(4,090,581)**	(4,090,581)	(0)	
		(222,600)	**(8,778,302)**	**6,072,600**	**(2,705,702)**	**3,040,110**				

Note 1: Disposition set out in the Board's Decision in London Hydro's 2009 COS Application (EB-2008-0235) for the period of Oct 1, 2009 to April 30, 2011.
Note 2: Disposition set out in the Board's Decision in London Hydro's 2012 IRM Application (EB-2011-0181) for the period of May 1, 2012 to April 30, 2014.

1588 RSVA Power (excluding Global Adjustment) recalculated with the amount for fixed price debit due to the IESO

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Debits	Total Net Accruals	Board Approved Disposition	Closing Balance
2008 Year-end accrual for Fixed Price Credit reversing in 2009				1,187,000	1,187,000		
Year 2009	(3,015,389)	(66,735)	(3,908,474)	2,269,300	(1,639,174)	3,040,110	(1,681,188)
Year 2010	(1,681,188)	(44,119)	(390,197)	349,800	(40,397)	-	(1,765,703)
Year 2011	(1,765,703)	(111,746)	(4,479,632)	2,266,500	(2,213,132)	-	**(4,090,581)**
		(222,600)	**(8,778,302)**	**6,072,600**	**(2,705,702)**	**3,040,110**	

The above table illustrates the fixed price debits for the unbilled portion of energy price differences due to the IESO using the foward method. The entry for the "fixed price debits" is the value of this outstanding liability. This liability is allocated to 2205 Accounts Payable Due to the IESO account from 1588 RSVA Power. The total actual paid/invoiced transactions, including carrying charges on paid/billed principal, are the same for over the years.

1588 RSVA Power Sub-account Global Adjustment as filed and reconciled to RRR 2.1.7

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Credits	Total Net Accruals	Board Approved Disposition	Closing Balance	RRR 2.1.7	Variance	
No fixed price credit accrued in Year 2008				-	-					
Year 2009	1,982,029	8,365	5,408,166	(4,262,161)	1,146,005	(2,001,899)	1,134,500	1,134,500	0	*Note 1.*
Year 2010	1,134,500	(2,644)	(2,882,212)	459,200	(2,423,013)	-	**(1,291,157)**	(1,291,157)	0	*Note 2.*
Year 2011	(1,291,157)	41,830	662,392	(1,998,139)	(1,335,747)	-	**(2,585,074)**	(2,585,074)	(0)	
		47,551	**3,188,345**	**(5,801,100)**	**(2,612,755)**	**(2,001,899)**				

Note 1: Disposition set out in the Board's Decision in London Hydro's 2009 COS Application (EB-2008-0235) for the period of Oct 1, 2009 to April 30, 2011.
Note 2: Disposition set out in the Board's Decision in London Hydro's 2012 IRM Application (EB-2011-0181) for the period of May 1, 2012 to April 30, 2014.

1588 RSVA Power Sub-account Global Adjustment recalculated with eliminating the amount for fixed price credit accrued in error after the accrual method is implemented

Year	Account 1589 Opening Balance	Carrying Charges	Net Accruals	Fixed Price Credits	Total Net Accruals	Board Approved Disposition	Closing Balance
No fixed price credit accrued in Year 2008				-	-		
Year 2009	1,982,029	8,365	5,408,166	(4,262,161)	1,146,005	(2,001,899)	1,134,500
Year 2010	1,134,500	(2,644)	(2,882,212)	4,262,161	1,379,948	-	**2,511,804**
Year 2011	2,511,804	41,830	662,392	-	662,392	-	**3,216,026**
		47,551	**3,188,345**	**-**	**3,188,345**	**(2,001,899)**	

The above tables illustrate after the last reversal of the fixed price debits/credits in 2012, the closing balance of the account is the same as if the fixed price debits/credits were accrued only for the time period the forward methodology was employed.
The total transactions, including carrying charges on paid/billed principal, are the same for over the years.

Respectfully Submitted