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October 15, 2013

BY COURIER & RESS

Ms. Kirsten Walli, Board Secretary
ONTARIO ENERGY BOARD
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: Board File No. EB-2013-0147
Kitchener-Wilmot Hydro Inc. – Interrogatory Responses

Dear Ms. Walli:

On July 21, 2013, Kitchener-Wilmot Hydro Inc. ("KWHI") filed its revised Cost of Service application for rates effective January 1, 2014. The Board issued Procedural Order #1 (PO#1) in this rates case on August 22, 2013. In accordance with the direction provided in PO#1, KWHI now files its responses to the Interrogatories of Board staff and registered Intervenors.

KWHI's submission, which has been previously electronically filed through the Board's web portal, consists of two (2) hard copies.

Respectfully submitted,

Original Signed by

Margaret Nanninga, MBA, CGA
Vice-President Finance

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EB-2013-0147

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Kitchener-Wilmot Hydro Inc. to the Ontario Energy Board for an Order approving just and reasonable rates and other charges, effective January 1, 2014.

INTERROGATORY RESPONSES OF KITCHENER-WILMOT HYDRO INC.

A. INTRODUCTION

1. Kitchener-Wilmot Hydro Inc. ("KWHI" or the "Applicant") owns and operates the electricity distribution system located in the City of Kitchener and the Township of Wilmot.

2. On May 17, 2013, KWHI filed its initial application with the Board File Number EB-2013-0147 to the Application.

3. Following discussion with Board staff, on June 21, 2013, KWHI re-submitted its Application using CGAAP as the accounting standard rather than MIFRS based on its decision to report in CGAAP for the year 2014.

4. The Board issued a Notice of Application and Letter of Direction on July 16, 2013. The publication of the Notice of Application and Affidavit stating the requirements of the Letter of Direction were fulfilled was submitted on July 19, 2013.

5. Energy Probe Research Foundation ("Energy Probe"), Vulnerable Energy Consumers Coalition ("VECC") and the School Energy Coalition (SEC) applied for Intervenor status and cost eligibility. The requests were accepted by the Board.

6. On August 22, 2013, the Board issued Procedural Order #1 (PO#1), which outlined the dates for the interrogatory process relating to this application. In PO#1, the Board stated that KWHI was to complete its responses to the interrogatories filed with it by October 15, 2013.

7. KWHI now files those responses as directed.

8. As a result of the interrogatory process, there have been changes made to the “live” rate models used by KWHI as outlined throughout this document.

Capital

9. KWHI has updated its capital forecasts for the year 2013 as requested by Energy Probe. The revenue requirement models have been updated to reflect these updates. The impacts to fixed assets are as listed below:

    a. Increased forecast 2013 capital expenditures of $724,900 (from $21,993,100 to $22,718,000) due to delays in delivery of some items from 2012 to 2013
    b. Decreased forecast 2013 capital contributions of $($689,500) (from $3,935,500 to $3,246,000).
    c. Increased amortization resulting from the adjustments above of $71,798 (from $7,705,054 to $7,776,852).
    d. Resulting in an increased to average net fixed assets for 2013 of $671,251 (from $170,896,787 to $171,568,037)

10. KWHI has made small changes to its 2014 capital expenditures forecasts for the year 2014. The changes to 2013 have resulted in variances to the ending balances for 2014 from the August 9, 2013 filing. The impacts to fixed assets are as listed below:

    a. Removal of increases to computer software and meter capital for fixed assets relating to account 1531 – Renewable Connection Capital which were included in the Direct Benefit Calculation.
    b. Misclassified computer software and hardware have been corrected.
    c. Increased forecast 2014 capital expenditures of $8,400 resulting from adjustments from 2013 to balance WIP in 2014.

d. Decreased amortization resulting from the adjustments above of $43,523 (from $8,205,853 to $8,162,330).
e. Resulting in an increased to average net fixed assets for 2014 of $1,344,763 (from $182,923,299 to $184,268,062)

Distribution Expenses

11. KWHI has updated its OM&A forecasts for the year 2013 as requested by VECC. Forecast distribution expenses have been increased by $86,500 for the year (from $17,807,575 to $17,893,075).
12. There have been no changes made to forecast distribution expenses for 2014; however, KWHI has adjusted its bad debt expense for 2013 by an additional $40,000 due to a typo in the original application.
13. KWHI's bad debt expense for 2014 was understated by $40,000; however, customer service/collecting was overstated by the same amount, resulting in no change to forecasted distribution expenses for 2014.
14. With regard to bad debt, KWHI believes that an additional $3,000 should be added to 2014 to bring it to $190,000 as job losses in Waterloo Region continue and KWHI has further concerns regarding 10,000 potential job losses resulting from the downturn of Blackberry.
15. KWHI notes that the inflation factors used in this application for non-labour inflation need to be updated to coincide with the Board's issued inflation factors.

Impact of Changes on 2014 Test Year

16. As a result of the changes made above:
    a. Rate base has increased by $1,183,348 (from $209,362,001 to $210,545,349).
    b. Working capital allowance decreased by $161,415 (from $26,438,702 to $26,277,287)
    c. Regulated rate of return has increased by $70,876 (from $12,539,688 to $12,610,564).

PILS & Interest Changes

17. CCA deductions for 2013 and 2014 PILS estimates have been adjusted to reflect the changes to fixed assets.
18. The Schedule 1 adjustment for 2013 for the addition to account 1576 for $3,676,200 has been removed.

19. Estimates of co-op and apprenticeship tax credits have been updated resulting in:
    a. Increased miscellaneous tax credits for 2013 of $8,000 (to $103,000 from $95,000).
    b. Decreased miscellaneous tax credits for 2014 of $18,000 (to $77,000 from $95,000).
20. Deemed interest expense has increased by $28,370 (from $5,019,405 to $5,047,775).
21. PILS have decreased by $52,959 (from $433,327 to $380,368).

Revenue Sufficiency

22. The revenue sufficiency has increased by $126,103 (from $793,268 to $919,371).

Changes included in the Updated Models (not covered above)

Load Forecast

23. KWHI has made the following changes to its load forecast as a result of the interrogatory process:
    - Updated the CDM activity variable to reflect the half-year rule impact of CDM programs in the first year;
    - Adjusted the kW forecast for the 2014 year based on using the average rate for 2002 through 2012 for the GS>50kW rate class;.
24. The kW demand for the Embedded Distributor was not changed as the interrogatories suggested different methodologies for arriving at an annual figure;
25. The resulting load forecast due to the above changes results in expected kWh sales of 1,796,009,002 kWh, an increase of 6,236,427 kWh or 0.3%.

Cost Allocation

26. KWHI discovered a billing error in its CIS during the preparation of the interrogatory responses. There are seven GS>50kW customer accounts that should have been receiving the customer-owned transformer discount (COT discount) that did not receive it in the past and 2 accounts that were receiving the discount and did receive it. KWHI has corrected the error in its CIS and is working to make the necessary adjustments to the customer accounts in a timely manner. The result is that the net annual demand for these accounts that is not included in the 2014 COT estimate is 16,572 kW. KWHI has adjusted its cost allocation model accordingly to incorporate the missing kW demand.
27. KWHI directly allocated $7,433 of costs to the embedded distributor as per VECC – 33,

Rate Design

28. No changes were made to Rate Design

Deferral & Variance Accounts

29. KWHI ran the direct benefit calculation on its balance of 1531 – Renewable Connection Capital and 1532 – Renewable Connection OM&A to arrive at rate riders for the direct benefits stemming from these regulatory assets. KWHI then recalculated its rate riders for its pool of regulatory assets and removed the amounts transferred from the fixed asset continuity schedule. The results of the analysis are as follows:

    1531 - Renewable Connection Capital – account balance $117,985

    - The direct benefit calculation, based on a one year rate rider calculated a direct benefit of $947. Assuming there is only a one year recovery of costs, the amount in the Renewable Connection - Capital line should be $7,079. This represents the direct benefit component on the $117,985 capital amount discussed above. Note the $7,079 is 6% of $117,985.
    - The amount to be recovered from the IESO as the provincial benefit would therefore be $110,906.

    1532 - Renewable Connection OM&A - account balance $37,405

    - The direct benefit calculation, based on a one year rate rider calculated a direct benefit of $3,209.
    - The amount to be recovered from the IESO as the provincial benefit would therefore be $34,196.

30. Account 1568 LRAMVA was updated to reflect only recoveries relating to 2011 & 2012 CDM program results plus 2011 program results persisting into 2012. The effect of the change is a reduction in the balance of account 1568 of ($22,096) (from $414,350 to $392,254)
31. Account 1576 has not been updated to reflect the updated CAPEX for 2013 as KWHI believes that the account balances are likely to change as outstanding issues need to be resolved.

Appendices Updated

32. KWHI has updated and (re)submitted the following appendices from the Filing Requirements:

a.	2-CN – 2-CQ	Depreciation Expense Schedules
b.	2-ED	Account 1576 Accounting Changes Under CGAAP
c.	2-FA & 2-FB	Direct Benefit Calculations
d.	2-I	Load Forecast CDM Form
e.	2-JB	OM&A Cost Drivers
f.	2-K	Employee Costs
g.	2-OB	2014 Debt Instruments
h.	2-TB	1592 Subaccount 1592 HSTOVAT Input Tax Credits

Board staff Interrogatories

Exhibit 1 – Administration

1-Staff-1 Ref: Exhibit 1/Tab 1/Schedule 7

KWHI has proposed an effective date for new rates of January 1, 2014. In this exhibit, KWHI states that it would require a final Rate Order by November 15, 2013 in order to implement new rates effective January 1, 2014.

Experience with numerous rate applications for Ontario electricity distributors beginning in 2006 indicates that most distributors can implement new rates and test their systems one or two weeks after the implementation date.

a) Please provide further explanation of why KWHI would require a final Rate Order 1.5 months in advance of when the new rates would come into effect.

Answer: KWHI has an internally developed Customer Information System requiring limited internal staff to make modifications to complex programs for rate changes. This, coupled with allowing ample time to test all rate changes in all class of customers, requires the lead time stated in KWHI's application.

b) Please identify when KWHI issues the first bills with consumption in the month of January.

Answer: It is anticipated that bills attracting the new rates will be issued on or about January 17, 2014.

1-Staff-2 Ref: Exhibit 1/Tab 1/Schedule 19 – Revenues from non-Distribution Activities, Exhibit 1/Tab 2/Schedule 9 – Affiliate Transactions and Exhibit 4/Tab 5/Schedule 1 –Shared Services & Corporate Cost Allocation

KWHI states, in this Exhibit 1/Tab 1/Schedule 19, that it has included the expenses and revenues related to two non-utility businesses:

- OPA-sponsored CDM programs; and
- Street lighting capital & maintenance (for affiliated and non-affiliated businesses)

Street-lighting capital and maintenance are provided to the affiliated City of Kitchener and Township of Wilmot (both the ultimate shareholders of KWHI through Kitchener Power Corporation) and to the Region of Waterloo and the Ontario Ministry of Transportation. The other referenced exhibits also deal with the streetlighting services provided currently through KWHI but intended to be provided through an affiliate once a service agreement is finalized.

a) KWHI states that streetlighting services are currently provided on a cost recovery basis. Does this mean that there is no return currently built into the capital services and the expensed services provided?

Answer: That is correct. All construction-type activities performed by KWHI have been historically completed on a cost recovery basis, regardless of whether the activities are distribution of electricity or street lighting. Consistent with the historical process, there has not been a return on capital added to the invoices issued for street lighting services; however, all related KWHI OM&A expenses are reduced by the OM&A costs recovered for the street lighting services.

b) In Exhibit 1/Tab 2/Schedule 9, KWHI states: "KWHI has provided street lighting capital and maintenance services to the City of Kitchener and the Township of Wilmot for many years. For these services, KWHI charges for all labour, material and overheads (plus a 9% administration charge) as it would for any other service provided to any other customer."

i. Please reconcile this with the cost recovery explanation provided in Exhibit 1/Tab 1/Schedule 9.

Answer: The amounts included in Exhibit 3/Tab 1/Schedule 9 do not include the administration fees charged to street lighting customers. Administration fees are recorded in KWHI's general ledger as direct expense reductions to USoA account 5005 – Operation Supervision & Engineering (2/3) & 5625 – Administrative Expense Transferred Out (1/3). The updated table below shows the administration charges that would have been charged to street lighting customers. Distribution expenses have separately been reduced by the 9% administration credit and are thus not included in 4375. The revenues are offset by the expenses recorded in 4380.

4375 - Street Lighting Services	Actual					Bridge	Test
	2008	2009	2010	2011	2012	2013	2014
Streetlighting Capital & Maintenance Services	1,186,519	1,246,988	950,852	1,086,061	1,049,783	1,195,400	1,219,300
Administration Charges	106,787	112,229	85,577	97,745	94,480	107,586	109,737
Total	**1,293,306**	**1,359,217**	**1,036,429**	**1,183,806**	**1,144,264**	**1,302,986**	**1,329,037**

ii. Please explain the rationale of the 9% administration charge for capital-related services.

Answer: The 9% administration charge applies to all billable work, regardless of whether it is capital or fully receivable (i.e. contributed capital, accidents, etc.). The 9% administration fee has been used for many years by KWHI and was calculated by management as a general proxy of the cost of administrating the accounts. Historical amounts and forecasted amounts for all administrative credits, including street lighting services, are provided below:

OEB Account	Account Description	2008	2009	2010	2011	2012	2013	2014
5005	Administration O/ H Credit	(371,407)	(275,642)	(378,199)	(306,143)	(450,565)	(358,800)	(368,800)
5625	Administration O/ H Credit	(185,703)	(138,161)	(189,237)	(189,294)	(189,060)	(179,400)	(184,400)
	Total	(557,110)	(413,803)	(567,436)	(495,436)	(639,625)	(538,200)	(553,200)

c) KWHI states that streetlighting services are expected to be transferred to an affiliated company, Kitchener Energy Services Inc. ("KESI"), and that, once service agreements are made with the agencies identified above, KWHI will outsource these services to KESI using a cost recovery basis plus a rate of return.

i. Will outsourcing to KESI involve transfer of any existing staff and/or capital assets (building or building space, office furniture and equipment, vehicles and rolling stock, etc.)?

Answer: **KWHI does not expect that the transferring of its street lighting activities to KESI will have any effect on staffing or capital. All costs incurred by KWHI to perform street light maintenance as a subcontractor will continue to be fully allocated and charged to KESI.**

ii. Outsourcing generally implies that the firm is the vendor with the customers, but that the services are provided through the outsourced firm. Who will be the vendor for the streetlighting capital and operating services provided to the City of Kitchener and others?

Answer: **KESI is expected to be the vendor for street lighting capital and operating services.**

iii. What is the current status of the planned outsourcing and service agreement?

Answer: **A draft service agreement has been submitted to the City of Kitchener. KESI is awaiting approval of the draft agreement. It is expected that, once signed, the service agreements with the other entities will soon follow.**

It should also be noted that the Ontario government has proposed to amend Regulation 161/99, which would allow LDCs to provide street lighting services within their service territory. It is expected that, if the regulation is amended, that KWHI will not transfer its street lighting activities to its affiliate, KESI, and street lighting services would stay within KWHI.

d) Have the resources and costs for both streetlighting services to be transferred to KESI and OPA-sponsored CDM programs been excluded from KWHI's 2014 revenue requirement? If not, please explain the treatment and the rationale for the treatment.

Answer: **The revenues and costs related to street lighting services have not been transferred to KESI in the revenue requirement model. $67,800 has been calculated as a return on capital for 2014 and is included as a revenue offset.**
All OPA revenues and costs have been removed for 2013 and 2014.

1-Staff-3 Ref: Exhibit 1/Tab 1/Schedule 22 – Conditions of Service

a) Please provide a summary of comments received with respect to the proposed Conditions of Service.

Answer: **No customer comments were received. One comment was received from KWHI staff re: clarifying the requirements for customer owned pole line.**

b) Please provide a brief summary of changes to the proposed Conditions of Service which KWHI may be making in light of any comments.

Answer: **Section 2.1.3 was edited to read "Kitchener-Wilmot Hydro Inc. may refuse to connect or continue to connect..", instead of "Kitchener-Wilmot Hydro Inc. may deny or continue to connect …".**

Sections 3.3.5.1, 3.3.5.2 and 3.3.5.3 were edited to add the following. "The customer's first service pole must be located within 30m of the closest connection point on Kitchener-Wilmot Hydro Inc.'s distribution".

Other minor changes made include; correcting typographical errors and adding a title to a table in Section 2.3.5.

c) Please indicate what, if any, impacts there may be on KWHI's current Application and proposed revenue requirement in light of any changes to the Conditions of Service.

Answer: **No impact is expected. No material change was made following the comments period.**

The CoS document is now finalised and issued and can be found on KWHI's website at ***http://kwhydro.com/Your-Service.htm***

1-Staff-4 Ref: Exhibit 1/Tab 2/Schedule 4 – Amortization Assumption

In this exhibit, KWHI states that:

> The pro-forma projections for the 2014 Test Year were prepared in accordance with KWHI's usual process, including the directives and assumptions described in E1/T2/S3, with the following exceptions:
> …

2) Amortization reflects the half-year rule for capital additions for the 2014 Test Year only.

What is KWHI's usual policy and practice with respect to calculation of amortization expense?

Answer: In preparing KWHI's budget each year, amortization is calculated as 100% in the year of acquisition. In the test year, KWHI prepares two budgets for amortization – one for internal use that uses 100% amortization in the year of acquisition, and one that uses the half year rule for capital additions in the year of acquisition for preparing its' Cost of Service. The amount of amortization presented in this Cost of Service application is using the half year rule.

1-Staff-5 Ref: Exhibit 1/Tab 3/Schedule 3 – Reconciliations to Audited Financial Statements

In Exhibit 1/Tab 3/Schedule 3, KWHI states: "Reconciliations between the audited financial statements and the results filed are provided in Tab 3, Schedule 4." Please confirm that the reference is to Exhibit 1/Tab 3/Schedule 3/Attachment 1.

Answer: Confirmed

1-Staff-6 Ref: Exhibit 1/Tab 3/Schedule 6 – Customer Satisfaction Survey

In Exhibit 1/Tab 3/Schedule 6 and the accompanying Attachment 1, KWHI provides the results of a Customer Satisfaction Survey that KWHI engaged an external firm, UtilityPULSE to conduct in 2012. KWHI notes that this is a follow-up to the first such survey of KWHI's customers conducted in 2008.

a) How does KWHI keep on top of customer satisfaction, expectations and emerging issues in between these surveys?

Answer: Through telephone, email and customer interaction, KWHI's front line staff is sensitive and trained to identify trends in customer issues and expectations. Regularly scheduled internal meetings are held to highlight and discuss solutions for any customer issues.

b) KWHI's results are compared against (Canada) National and "Ontario" results. What is the coverage, in terms of Ontario electricity distributors and in the percentage of Ontario electricity ratepayers, represented by the "Ontario" results?

Answer: The residential customer and small general service customer data comes from the 2012 Customer Satisfaction Survey conducted for KWHI by Simul/UtilityPulse. UtilityPULSE is a company that specializes in surveying/polling electric utility customers. In 2012 UtilityPULSE conducted surveys for 15 Ontario LDCs (including KWHI) out of a population of 73 (2012 Electricity Yearbook). In addition to the 15 LDCs that participated in 2012, UtilityPULSE also produces an Ontario benchmark which involves a data sample covering all residential and small commercial customers in Ontario. The 2012 Electricity Yearbook shows

that there are 4,836,620 residential and small commercial customers in Ontario. The Ontario benchmark is based on interviews with residential and small commercial customers across the province and it has a statistical confidence ratio of less than +/- 3.1%, 19 times out of 20. The statistical confidence ratio for the group of utilities in the 2012 survey is less than +/- 2.1%, 19 times out of 20.

Customers	15 Participating LDCs	Ontario LDCs	Coverage of 15 Participated LDCs
Residential Customers	1,676,520	4,406,331	38.00%
Small Commercial	151,618	430,289	35.20%
Overall	1,828,138	4,836,620	37.80%
Survey Confidence Level	+/- 2.1%	+/- 3.1%	

c) How is KWHI using the results of the Customer Satisfaction Survey in its business plan and budgeting, and in its long-term capital and operating plan forecast?

Answer: There are two primary areas of concern from the survey - rising electricity bills and reliability concerns. KWHI has engaged a firm to develop a strategic communications plan to address the first issue. There are many reasons for rising electricity costs and additional consumer education is planned in the coming months. With respect to reliability, KWHI has devoted considerable time to analyzing the root causes of distribution system outages and has implemented a number of programs over the last several years to reduce outages. These include additional tree trimming, animal proofing of distribution transformers and line switches and installing drains in submersible transformer vaults. These are multi-year initiatives which will be monitored for their effectiveness on an on-going basis.

d) How have the results of the Customer Satisfaction Survey been reflected in this Application?

Answer: See response above.

e) Has KWHI taken other steps with respect to measuring customers or engaging customers to understand their expectations? If so, how does KWHI use or link this information with maintaining and improving operational processes in light of the results?

Answer: On-going feedback is received from KWHI's customers through personal contact, telephone calls and written feedback. The year 2013 has been a challenging year for major storms and equipment damage. A number of suggestions have been made to improve KWHI's communications with customers during a storm event. KWHI is currently investigating a number of options to improve its customer communications as part of developing its strategic communications plan including the use of social media and regular telephone message updates. KWHI is also in the process of evaluating and implementing an Outage Management System to provide better information to improve its response during a storm.

1-Staff-7 Ref: Exhibit 1/Tab 2/Schedule 1/page 2 – Account 1531 Renewable Connection Capital and *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (EDDVAR), p. 24, dated July 31, 2009

KWHI is requesting approval to transfer the December 31, 2012 balance plus projected carrying charges to December 31, 2013 of Account 1531 – Renewable Connection Capital as of December 31, 2012 directly to capital effective January 1, 2014, rather than through a Deferral and Variance Account rate rider.

Board staff notes that KWHI's proposal to transfer the balance of Account 1531 directly to capital instead of via a rate rider is not consistent with the guideline in the Board Report on EDVARR which states, at page 24:

Board's Policy and Rationale:

> The Board agrees that a volumetric rate rider to dispose of the deferral and variance account balances is appropriate.

a) Please provide further explanation of why KWHI is requesting disposition in a manner inconsistent with the Board's documented policy and practice that recovery should be through a DVA rate rider.

Answer: KWHI felt that, due to the low dollar amounts in account 1531 coupled with the fact that the most of the costs were related to KWHI's own Customer Information System, the majority of the costs constituted direct benefits to KWHI's own customers.

b) Please provide rate riders for disposition of the December 31, 2013 balance of principal and carrying charges under a scenario where the Board approves disposition through rate riders instead of as proposed by KWHI. Please show the derivation of the estimated rate riders.

Answer: See Table below:

Rate Rider Calculation (Net of Global Adjustment) - 1531 Added

Deferral and Variance Accounts	Balances at Dec. 31, 2013	ALLOCATOR	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor	Total
RSVA - Wholesale Market Service Charge	$ (6,807,358)	kWh - No Embedded Distributor	$ (2,479,547)	$ (918,961)	$ (3,213,540)	$ (120,960)	$ (12,999)	$ (61,351)	$ -	$ (6,807,358)
RSVA - Retail Transmission Network Charge	$ 4,155,637	kWh - Embedded Distributor	$ 1,496,669	$ 554,690	$ 1,939,712	$ 73,012	$ 7,846	$ 37,032	$ 46,676	$ 4,155,637
RSVA - Retail Transmission Connection Charge	$ 295,255	kWh - Embedded Distributor	$ 106,337	$ 39,410	$ 137,815	$ 5,187	$ 557	$ 2,631	$ 3,316	$ 295,255
RSVA - Power	$ 1,458,793	kWh - No Embedded Distributor	$ 531,358	$ 196,930	$ 688,651	$ 25,921	$ 2,786	$ 13,147	$ -	$ 1,458,793
RSVA - Global Adjustment	$ -	kWh for non-RPP customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances (2010)	$ 371,371	Recovery Share	$ 146,298	$ 59,668	$ 157,034	$ 4,327	$ -	$ 4,044	$ -	$ 371,371
Subtotal - Group 1	**$ (526,302)**		**$ (198,885)**	**$ (68,262)**	**$ (290,329)**	**$ (12,512)**	**$ (1,810)**	**$ (4,497)**	**$ 49,992**	**$ (526,302)**
Other Regulatory Assets-Sub-Account - IFRS Transition Costs	$ 197,646	Distribution Revenue	$ 103,503	$ 27,938	$ 60,059	$ 2,737	$ 760	$ 2,360	$ 289	$ 197,646
Retail Cost Variance Account - Retail	$ (71,407)	# of Customers	$ (62,839)	$ (5,958)	$ (719)	$ (1)	$ (677)	$ (1,211)	$ (1)	$ (71,407)
Renewable Connection - Capital	$ 117,986	Distribution Revenue	$ 61,787	$ 16,678	$ 35,852	$ 1,634	$ 454	$ 1,409	$ 172	$ 117,986
Renewable Connection - OM&A	$ 37,405	Distribution Revenue	$ 19,588	$ 5,287	$ 11,366	$ 518	$ 144	$ 447	$ 55	$ 37,405
Retail Cost Variance Account - STR	$ 40,052	# of Customers	$ 35,246	$ 3,342	$ 403	$ 0	$ 380	$ 680	$ 0	$ 40,052
LRAM Variance Account	$ 414,350	CDM Savings	$ 117,229	$ 119,290	$ 177,831	$ -	$ -	$ -	$ -	$ 414,350
PILS & Taxes Variance - 2006 & Subsequent Years	$ (244,779)	Distribution Revenue	$ (128,186)	$ (34,601)	$ (74,381)	$ (3,390)	$ (942)	$ (2,923)	$ (357)	$ (244,779)
PILS & Taxes Variance - Sub-Account HST/OVAT	$ (162,202)	Distribution Revenue	$ (84,942)	$ (22,928)	$ (49,288)	$ (2,246)	$ (624)	$ (1,937)	$ (237)	$ (162,202)
Subtotal - Group 2	**$ 329,050**		**$ 61,387**	**$ 109,048**	**$ 161,123**	**$ (747)**	**$ (505)**	**$ (1,176)**	**$ (79)**	**$ 329,050**
Total to be Recovered	**$ (197,252)**		**$ (137,498)**	**$ 40,786**	**$ (129,206)**	**$ (13,259)**	**$ (2,314)**	**$ (5,673)**	**$ 49,913**	**$ (197,252)**
Balance to be collected or refunded, Variable	$ (197,252)		$ (137,498)	$ 40,786	$ (129,206)	$ (13,259)	$ (2,314)	$ (5,673)	$ 49,913	$ (197,252)
Number of years for Variable	**1**									
Balance to be collected or refunded per year, Variable	$ (197,252)		$ (137,498)	$ 40,786	$ (129,206)	$ (13,259)	$ (2,314)	$ (5,673)	$ 49,913	$ (197,252)

Class	**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**Large User**	**Unmetered Scattered Load**	**Street Lighting**	**Embedded Distributor**
Deferral and Variance Account Rate Rider, Variable / **Billing Determinants**	$ (0.0002) kWh	$ 0.0002 kWh	$ (0.0599) kW	$ (0.2105) kW	$ (0.0007) kWh	$ (0.1257) kW	$ 1.1173 kW

End of Board Staff Exhibit One Interrogatories

Energy Probe Interrogatories

<u>1-Energy Probe-1</u>

Ref: Exhibit 1, Tab 1, Schedule 1

Has there been any change in the transmission assets that were previously deemed by the Board as distribution assets?

Answer: No. The transmission assets currently deemed to be distribution assets are the eight transformer stations listed in Exhibit 1 Tab 1 Schedule 10. The transmission assets deemed by the OEB to be distribution assets four years ago in KWHI's last COS application are the same eight transformer stations.

<u>1-Energy Probe-2</u>

Ref: Exhibit 1, Tab 1, Schedule 19

What is the current status of the movement of street lighting services to Kitchener Energy Services Inc.?

Answer: **See Board interrogatory 1-Staff-2.**

1-Energy Probe-3

Ref: Exhibit 1, Tab 2, Schedule 9

Does KWHI pay any costs associated with the Board of Directors of its parent company, or the affiliate KESI? If yes, please provide the 2014 test year forecast of these costs to be paid by KWHI and describe the allocation methodology used to determine the amount.

Answer: **KWHI does not pay any costs associated with the Board of Directors for either its parent or KESI.**

End of Energy Probe Exhibit One Interrogatories

School Energy Coalition Exhibit One Interrogatories

1-SEC-1

Please confirm that there are 86 schools in the Applicant's franchise area from three school boards. Please advise the number of schools in each of the GS<50 and GS>50 classes.

Answer: **There are 84 schools. See below:**

Separate School Board		
27 schools	**18 GS >50**	**9 GS <50**
Public School Board		
54 schools	**45 GS >50**	**9 GS <50**
Private		
3 schools	**2 GS > 50**	**1 GS <50**

1-SEC-2

[1/1/12]

Please advise whether a merger of the contiguous utilities is possible or contemplated within the time frame of the IRM term.

Answer: **It is not expected that KWHI will be involved in a merger with contiguous utilities prior to 2018.**

1-SEC-3

[1/2/1, p. 5]

Please provide the annual revenue requirement impact of the capital component of owning the eight transformer stations, plus any impact on annual charges from Hydro One, to go along with the $17.01 per customer operating costs.

Answer: The total revenue requirement for transformer station capital (inclusive of OM&A, taxes and interest) would be $7,083,277. Upon removing the OM&A portion of the revenue requirement, the net revenue requirement would be $3,443,977 (inclusive of interest & taxes). Revised portion of the FA continuity and revenue requirement schedules are below.

Fixed Asset Continuity Schedule (Distribution & Operations)
CGAAP
as at December 31, 2014

		Cost					Accumulated Depreciation					
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Transfers**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Transfers**	**Closing Balance**	**Net Book Value**
1805	Land											
1806	Land Rights											
1808	Buildings and Fixtures											
1808	Buildings	8,878,198	158,000			9,036,198	2,356,506	186,400			2,542,906	6,493,293
1808	Roof	166,229	3,200			169,429	74,740	12,700			87,440	81,988
1815	Transformer Station Equipment - Normally Primary above 50 kV											
1815	Equipment - 50 Years	22,277,769	650,000			22,927,769	7,113,839	411,100			7,524,939	15,402,830
1815	Equipment - 40 Years	34,605,591	1,390,000			35,995,591	11,588,190	881,000			12,469,190	23,526,402
1815	Equipment - 25 Years	1,527,950				1,527,950	599,779	87,300			687,079	840,870
1815	Equipment - 20 Years	581,964				581,964	294,895	41,500			336,395	245,569
1815	Equipment - 15 Years	1,667,362				1,667,362	860,429	146,000			1,006,429	660,933
1810	Leasehold Improvements											
1995	OEB Clearing											
	Total before Work in Process	**69,705,063**	**2,201,200**			**71,906,263**	**22,888,378**	**1,766,000**			**24,654,378**	**47,251,884**
2070	Other Utility Plant											
	Work in Process											
	Total after Work in Process	**69,705,063**	**2,201,200**			**71,906,263**	**22,888,378**	**1,766,000**			**24,654,378**	**47,251,884**

Revenue Sufficiency/Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test Required Revenue
Revenue:			
Revenue Deficiency			**7,083,277**
Distribution Revenue			
Other Operating Revenue (Net)			
Accounting Changes Under CGAAP - Account 1576			
Total Revenue			**7,083,277**
Costs and Expenses:			
Administrative & General, Billing & Collecting			
Operation & Maintenance	1,777,100	1,873,300	1,873,300
Depreciation & Amortization	1,772,500	1,766,000	1,766,000
Property Taxes			
Capital Taxes			
Deemed Interest	1,572,818	1,133,475	1,133,475
Total Costs and Expenses	**5,122,418**	**4,772,775**	**4,772,775**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**5,122,418**	**4,772,775**	**4,772,775**
Utility Income Before Income Taxes	**(5,122,418)**	**(4,772,775)**	**2,310,502**
Income Taxes:			
Corporate Income Taxes		(1,264,785)	612,283
Total Income Taxes		**(1,264,785)**	**612,283**
Utility Net Income	**(5,122,418)**	**(3,507,989)**	**1,698,219**

Revenue Sufficiency/Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test Required Revenue
Revenue:			
Revenue Deficiency			**3,443,977**
Distribution Revenue			
Other Operating Revenue (Net)			
Accounting Changes Under CGAAP - Account 1576			
Total Revenue			**3,443,977**
Costs and Expenses:			
Administrative & General, Billing & Collecting			
Operation & Maintenance			
Depreciation & Amortization			
Property Taxes			
Capital Taxes			
Deemed Interest	1,572,818	1,133,475	1,133,475
Total Costs and Expenses	**1,572,818**	**1,133,475**	**1,133,475**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**1,572,818**	**1,133,475**	**1,133,475**
Utility Income Before Income Taxes	**(1,572,818)**	**(1,133,475)**	**2,310,502**
Income Taxes:			
Corporate Income Taxes		(300,371)	612,283
Total Income Taxes		**(300,371)**	**612,283**
Utility Net Income	**(1,572,818)**	**(833,104)**	**1,698,219**

KWHI does not pay any annual charges to Hydro One as it owns all of its own transformer stations.

1-SEC-4

[1/2/9, p. 2]

Please advise why KPC is not being charged for Accounting Services on a fully allocated basis, i.e. a proportionate share of all costs associated with the function, not just incremental costs.

Answer: KWHI submits that the amount allocated to KPC is proportionate to the function being performed as the only work performed by KWHI staff for KPC is the preparation of KPC's annual reports and bank reconciliations. KPC is not involved in any other business and costs are quite low.

End of School Energy Coalition Exhibit One Interrogatories

VECC Exhibit One Interrogatories

1.0- VECC- 1

Reference: Exhibit 4, Tab 2, Schedule 2, Schedule 5, Schedule 8

a) Please explain how KWHI communicates the availability of the LEAP program to its existing and potential customers?

Answer: KWHI promotes the LEAP program by the following:

- **Reference is made to the program on all hand-delivered termination notices**
- **The Region of Waterloo Social Services promotes the program by brochures distributed at their office, community centres throughout the region, and community outreach program locations. KWHI also has brochures at its office for customers.**
- **KWHI's collection staff distribute the above brochures and are trained to introduce the program to customers.**
- **The program is fully detailed including contact information on KWHI's website.**

b) Who is KWHI's LEAP social agency partner?

Answer: The Region of Waterloo Social Services.

c) Has KWHI been provided an accounting of the donations made in 2011 and 2012? If yes please provide this summary.

Answer: Yes, See Appendix B

End of Exhibit One Interrogatories

Board Staff Exhibit Two Interrogatories

Exhibit 2 – Rate Base

2-Staff-8 Ref: Exhibit 2/Tab 7/Schedule 1/ Attachment 1 – Green Energy Act Plan (p. 8/section 3.3 & Appendix A)

Under "Station Capacity", it is stated, in part, that:

> […]All transformer stations have sufficient short-circuit capacity to accommodate the type of distributed generation that Kitchener-Wilmot Hydro has seen so far. Most of the renewable energy projects proposed in Kitchener-Wilmot Hydro service area are inverter-based with limited fault contribution to Kitchener-Wilmot Hydro's distribution system. […] For all Kitchener-Wilmot Hydro transformer stations, the station capacity is limited by the thermal capacity of the station transformers. <u>Dual-winding transformers are installed at Kitchener #3, #4, #5 and #6 MTS. These dual-winding transformers cannot sustain reverse power flow, thus the station thermal capacity is determined by the minimum station load</u>. [Emphasis added]

a) Did KWHI perform any special assessments to determine the extent to which each of the four transformer stations (i.e. Kitchener #3, #4, #5 and #6 MTS) can withstand reverse power flow? If not, would KWHI consider exploring this issue with other utilities (e.g., Hydro One Networks Inc.) that may have the same type of transformer design in some of their transformer stations?

Answer: KWHI did not perform any special assessments.

KWHI has consulted the manufacturers of its dual-winding transformers. Based on information from the transformer manufacturers, KWHI has determined that some dual secondary winding transformers cannot withstand forward flow in one secondary winding while there is reverse flow in the other secondary winding, and excessive imbalance between the two secondary windings causes core and clamp overheating and potential failure of the transformer. Hydro One was the first utility who addressed this issue. The same limits apply to some of its transformer stations with dual LV winding transformers.

b) Do all dual-winding transformers have the same design limitation in regards to overheating due to reverse power flow, irrespective of vintage?

Answer: All of KWHI's transformers with dual LV windings share a design with a similar arrangement of the two LV windings and would have similar design limitations. KWHI doesn't know if all transformers with dual LV windings share the same design as the transformers owned by KWHI.

c) Please comment on the view that the issue of overheating related to power flow between the two low voltage windings can also occur due to unbalanced distribution of load between the two buses that connect to the two windings. If this is the situation, can rebalancing the amounts of generation and load be used to increase the amount of permissible generation in the noted four stations?

Answer: An unbalanced distribution of load between the two buses does not cause a transformer to overheat as long as the currents in both LV windings flow in the same direction.

2-Staff-9 Ref: Exhibit 2/Tab 4/Schedule 7, Exhibit 2/Tab 7/Schedule 1/ Attachment 1 of 1 – Green Energy Act Plan, and Report of the Board – Framework for Determining the Direct Benefit Accruing to Consumers of a Distributor under Ontario Regulation 330/09 issued June 10, 2010 [EB-2009-0349]

At page 2, lines 23 – 28 of Exhibit 2/Tab 4/Schedule 7, KWHI states:

> KWHI's renewable generation costs through 2017 consist of Renewable Enabling Improvements (REI) only. Currently, KWHI has already spent $114,470 in capital and $36,410 in OM&A costs to enable the connection of renewable generation during the period 2010-2012. These costs were transferred to deferral accounts 1531 – Renewable Connection Capital and 1532 – Renewable Connection OM&A. In Exhibit 9 of this application, KWHI has requested clearance of these accounts for audited balances up to December 31, 2012.

The referenced Report of the Board requires that any distributor who incurred eligible capital and OM&A costs necessary for the purpose of "enabling the connection of qualifying generation facility" (see page 3 at Section 1.1 Regulation 330/09, & first bullet), to calculate the "direct benefits" to customers of the distributor per Section 3.2.2.3 of that same Report of the Board.

In KWHI's Green Energy Act Plan, at page 12, Table 5 documents Capital ($114,470) and OM&A ($36,410) expenditures recorded under the column "Actual 2010 – 2012" at the row "Renewable Generation". At page 13, Table 6 depicts the "Direct Benefit Calculation", for the years 2015-2017, and does not show "Direct Benefit Calculation" with respect to the Capital ($114,470) under "Actual 2010-2012:, which is broken down to:

- ($103,490) under "FIT/microFIT CIS Changes"; and
- ($10,980) under "MicroFIT Meter Capital".

a) What are the reasons for not performing the Direct Benefit Calculation on the $103,490 of Capital investment for "FIT/microFIT CIS Changes" for the 2010-2012 period?

Answer: KWHI had applied for the balance of account 1531 to be transferred directly to capital (as the balance is mostly software changes to the CIS) so the direct benefit calculation was not performed. See 1-Staff-7 a).

b) Please explain the reasons for having no capital investments for 2013 and 2014, yet show investments for "Scada Programming & Wiring Changes" as well as for "Station P&C Upgrades" for the years 2015 – 2017.

Answer: **Investments for "Scada Programming & Wiring Changes" and "Station P&C Upgrades" are required to accommodate the connection of renewable generation projects larger than 250kW. "Scada Programming & Wiring Changes" are required for each generation project larger than 250kW. "Station P&C Upgrades" are required for each generation project larger than 1MW.**

The OPA conducted a review of the FIT program in 2012. The OPA did not open up a window for receiving applications for FIT projects larger than 250kW until January 2013. There were no FIT projects >250kW connected (or to be connected) in the KWHI service area in 2013. Given the 18-24 month time required to take a FIT project >250MW from initial application to in service, it was KWHI's belief that it was unlikely that any capital expenditures would be required in 2014 for FIT projects >250MW; therefore, KWHI's Green Energy Act Plan forecast capital expenditures related to "Scada Programming & Wiring Changes" and "Station P&C Upgrades" for FIT projects >250kW in years 2015 through 2017 only.

c) Please explain why the $10,980 Capital under "MicroFIT Meter Capital" for the "Actual 2010-2012" is not subject to Direct Benefit Calculation for the Actual 2010-2012 period?

Answer: **KWHI notes that the $10,980 in meter capital was below the materiality threshold as defined by the OEB for KWHI in the filing requirements. As a result it was classified as being immaterial. See 1-Staff-7.**

d) Would KWHI agree to use the default values, in the absence of utility- or project-specific ones, for calculating the Direct Benefit Calculation?

Answer: **Yes**

2-Staff-10 Ref: Exhibit 2/Tab 7/Schedule 1/ Attachment 1 of 1 – Green Energy Act Plan/Appendix C

In the reference above, at page 18, under "section 4. For Renewable Generation OM&A", lines 20 – 34, KWHI states:

> Kitchener-Wilmot Hydro has been able to manage the workload related to processing renewable energy applications using existing staff and hiring co-op students rather than by creating new permanent positions. A co-op student is hired during the summer and fall work terms when the microFIT demand is high. The student is dedicated to responding to the microFIT inquiries, conducting the site visits, preparing the Offers to Connect and microFIT data entries. To meet the microFIT project timeline, some permanent staff had to work overtime. Temporary students and staff overtime may be required through 2017 to meet the ongoing workload. Kitchener-Wilmot Hydro tracks the temporary labour and overtime costs in a Renewable Energy Deferral Account.

Costing:
2013: $25,000
2014: $25,000
2015: $25,000
2016: $25,000
2017: $25,000

The Report of the Board noted in the previous interrogatory requires that any distributor who incurred eligible capital and OM&A costs necessary for the purpose of "enabling the connection of qualifying generation facility" (see page 3 at Section 1.1 Regulation 330/09, & first bullet), to calculate the "direct benefits" to customers of the distributor per Section 3.2.2.3 of that same Report of the Board.
Would KWHI agree to calculate the Direct Benefit Calculation as required by the second reference for the $25,490 of OM&A costs related to Renewable Generation OM&A for 2013 and for 2014, as well as for the remaining years of the 5 year plan (i.e., for 2015, 2016, and 2017) using the default values if it does not have utility- or program-specific values?

Answer: **Yes, although the numbers are not of a material nature.**

2-Staff-11 Ref: Exhibit 2/Tab 7/Schedule 1/Attachment 1 – Green Energy Act Plan, Ministry of Energy Directive to the OPA, November 23, 2012 and Ministry of Energy Directive to the OPA, June 12, 2013

The OPA's Letter of Comment included as Appendix D to KWHI's Green Energy Act Plan reports that, according to OPA's information to date [as of the date of the OPA's letter dated April 19, 2013], the OPA has received and offered contracts to:

- 245 microFIT projects, totalling approximately 1.9 MW of capacity in Kitchener-Wilmot Hydro's distribution system.
- Additionally, the OPA has received and offered contracts to 35 FIT applications. Of these, 7 applications totalling 1.6 MW have come into commercial operation and 16 applications totalling 2.6 MW remained active as of April 2013. [Emphasis added]

In KWHI's Green Energy Act Plan, at page 9, Section 4.1, KWHI states that;

- based on the OPA there are 48 small FIT applications under FIT 2.0 with a total proposed capacity of 8.2 MW (refer to Appendix B).
- due to the 200 MW provincial cap for small FIT applications, it is reasonable to estimate that only 25-30% of these applications can be awarded the conditional offer under FIT2.0 in 2013. And it is also reasonable to estimate that the remaining customers who cannot receive the FIT contract under FIT 2.0 in 2013 will choose to pursue at a later time.

The second reference corroborates KWHI's reference, to the Ministry of Energy's Directive to the OPA dated November 23, 2012, setting the 200 MW provincial cap for small FIT applications for 2013.

The third reference, Ministry of Energy's Directive to the OPA dated June 12, 2013 sets a 150 MW provincial cap for small FIT applications for each of the next four years (i.e., for 2014, 2015, 2016 and 2017).

a) Please provide the basis for the assumption in the second reference where KWHI indicated that it is reasonable to estimate that only 25-30% of these applications can be awarded the conditional offer under FIT 2.0 in 2013.

Answer: On January 28th, 2013, the OPA announced that there were 3,839 applications with total capacity of 825,575KW under FIT 2.0. Comparing the total capacity of all applications (826MW) to the 200 MW provincial cap for small FIT applications for 2013 set by the Ministry of Energy's Directive to the OPA dated November 23, 2012, KWHI estimated that only 25-30% of these applications can be awarded a conditional offer under FIT 2.0 in 2013.
http://fit.powerauthority.on.ca/newsroom/january-28-summary-of-small-FIT-applications

b) Based on the 150 MW provincial cap for small FIT applications for the years 2014, 2015, 2016 and 2017, cited in the fourth reference, please provide a revised forecast for the FIT projects, by updating Table 3 of the second reference.

Answer: The assumption for small FIT applications for the years 2014, 2015, 2016 and 2017 was based on the historical FIT data and multiple assumptions. The change of the provincial cap from 200MW to 150MW may reduce the number of FIT applications awarded contracts in KWHI's service area. However, KWHI doesn't know how to quantify this impact. Furthermore, this reduction of the provincial cap won't change the essential conclusion of KWHI's Green Energy Act Plan, specifically that "it is estimated that Kitchener-Wilmot Hydro has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects under FIT/microFIT program between 2013-2017".

2-Staff-12 Ref: Exhibit 9/Tab 1/Schedule 1/pp. 8, 10 and 14

At pages 8 and 10, for the Deferral Account "Renewable Connection Capital", the amount of "Total Principal & Interest" is $116,303.29 as of December 31, 2012.
At page 14, KWHI states:

> Lastly, KWHI is applying to clear the balance of its account 1531 – Renewable Connection – Capital – to capital, rather than clearing the balance through a rate rider.

The Report of the Board referenced in 2-Staff-3 requires that any distributor who incurred eligible capital and OM&A costs necessary for the purpose of "enabling the connection of qualifying generation facility" (see page 3 at Section 1.1 Regulation 330/09, & first bullet) to calculate the "direct benefits" to customers of the distributor per Section 3.2.2.3 of that same Report of the Board.
Please file a calculation of the rate rider to clear the deferral account 1531 as outlined below in accordance with the approach documented in the Report of the Board:

- o first, calculate the interest for January 1 to December 31, 2013, and add that amount of interest to the $116,303.29 being the "Principal and Interest at Dec 31, 2012";

Answer: **KWHI has calculated the interest on the assets as requested which results in a total value of $117,985; however, the total value of the $117,985 is made up of two different types of assets with different amortization and CCA rates. The assets (and corresponding interest calculations) have been split accordingly in the table below:**

1531 - Renewable Connection Capital - Asset Split by Type

	Year	Capital	Interest	Total
CIS Software	2009	15,663	6	15,669
	2010	9,765	186	9,951
	2011	87,972	1,060	89,032
	2012	(9,909)	1,487	(8,422)
	2013		1,521	1,521
		103,491	4,260	107,751
Meter	2009	-	-	-
	2010	-	-	-
	2011	(24,261)	-	(24,261)
	2012	35,244	(910)	34,334
	2013		161	161
		10,983	(749)	10,234
Total	2009	15,663	6	15,669
	2010	9,765	186	9,951
	2011	63,711	1,060	64,771
	2012	25,335	577	25,912
	2013		1,683	1,683
		114,474	3,511	117,985

- second, perform the direct benefit calculation, as prescribed in the Report of the Board, on the total amount calculated in the bullet above. This is required since the noted capital is an eligible amount according to the second reference; and

Answer: KWHI has performed the direct benefit calculation as requested. Since the balance of $117,985 is made up of two different assets with differing amortization and CCA rates, KWHI has modified the worksheet “App.2-FB Calc of REG Improvement” to include two fixed asset calculations for amortization and CCA. Note that the calculation for account 1532 – Renewable Connection OM&A is also included in the calculation. The direct benefit is calculated to be $3,209. The Appendix 2-FA & FB are included in Appendix A.

- third, to propose the disposition and recovery of the portion designated as direct benefit, from the calculation in the bullet above, through a rate rider.

Answer: KWHI has updated all of the balances to be recovered for accounts 1531 and 1532 to be the direct benefit amounts arising from the calculation.

Rate Rider Calculation (Net of Global Adjustment) - 1531, 1532 Added and 1568 Adjusted

Deferral and Variance Accounts	Balances at Dec. 31, 2013	ALLOCATOR	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor	Total
RSVA - Wholesale Market Service Charge	$ (6,807,358)	kWh - No Embedded Distributor	$ (2,479,547)	$ (918,961)	$ (3,213,540)	$ (120,960)	$ (12,999)	$ (61,351)	$ -	$ (6,807,358)
RSVA - Retail Transmission Network Charge	$ 4,155,637	kWh - Embedded Distributor	$ 1,496,669	$ 554,690	$ 1,939,712	$ 73,012	$ 7,846	$ 37,032	$ 46,676	$ 4,155,637
RSVA - Retail Transmission Connection Charge	$ 295,255	kWh - Embedded Distributor	$ 106,337	$ 39,410	$ 137,815	$ 5,187	$ 557	$ 2,631	$ 3,316	$ 295,255
RSVA - Power	$ 1,458,793	kWh - No Embedded Distributor	$ 531,358	$ 196,930	$ 688,651	$ 25,921	$ 2,786	$ 13,147	$ -	$ 1,458,793
RSVA - Global Adjustment	$ -	kWh for non-RPP customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances (2010)	$ 371,371	Recovery Share	$ 146,298	$ 59,668	$ 157,034	$ 4,327	$ -	$ 4,044	$ -	$ 371,371
Subtotal - Group 1	**$ (526,302)**		**$ (198,885)**	**$ (68,262)**	**$ (290,329)**	**$ (12,512)**	**$ (1,810)**	**$ (4,497)**	**$ 49,992**	**$ (526,302)**
Other Regulatory Assets-Sub-Account - IFRS Transition Costs	$ 197,646	Distribution Revenue	$ 103,503	$ 27,938	$ 60,059	$ 2,737	$ 760	$ 2,360	$ 289	$ 197,646
Retail Cost Variance Account - Retail	$ (71,407)	# of Customers	$ (62,839)	$ (5,958)	$ (719)	$ (1)	$ (677)	$ (1,211)	$ (1)	$ (71,407)
Renewable Connection - Capital	$ 7,079	Distribution Revenue	$ 3,707	$ 1,001	$ 2,151	$ 98	$ 27	$ 85	$ 10	$ 7,079
Renewable Connection - OM&A	$ 3,209	Distribution Revenue	$ 1,680	$ 454	$ 975	$ 44	$ 12	$ 38	$ 5	$ 3,209
Retail Cost Variance Account - STR	$ 40,052	# of Customers	$ 35,246	$ 3,342	$ 403	$ 0	$ 380	$ 680	$ 0	$ 40,052
LRAM Variance Account	$ 392,254	CDM Savings	$ 110,977	$ 112,929	$ 168,348	$ -	$ -	$ -	$ -	$ 392,254
PILS & Taxes Variance - 2006 & Subsequent Years	$ (244,779)	Distribution Revenue	$ (128,186)	$ (34,601)	$ (74,381)	$ (3,390)	$ (942)	$ (2,923)	$ (357)	$ (244,779)
PILS & Taxes Variance - Sub-Account HST/OVAT	$ (162,202)	Distribution Revenue	$ (84,942)	$ (22,928)	$ (49,288)	$ (2,246)	$ (624)	$ (1,937)	$ (237)	$ (162,202)
Subtotal - Group 2	**$ 161,851**		**$ (20,852)**	**$ 82,176**	**$ 107,547**	**$ (2,757)**	**$ (1,063)**	**$ (2,909)**	**$ (291)**	**$ 161,851**
Total to be Recovered	**$ (364,451)**		**$ (219,737)**	**$ 13,913**	**$ (182,782)**	**$ (15,269)**	**$ (2,873)**	**$ (7,405)**	**$ 49,701**	**$ (364,451)**
Balance to be collected or refunded, Variable	$ (364,451)		$ (219,737)	$ 13,913	$ (182,782)	$ (15,269)	$ (2,873)	$ (7,405)	$ 49,701	$ (364,451)
Number of years for Variable	1									
Balance to be collected or refunded per year, Variable	$ (364,451)		$ (219,737)	$ 13,913	$ (182,782)	$ (15,269)	$ (2,873)	$ (7,405)	$ 49,701	$ (364,451)

Class	**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**Large User**	**Unmetered Scattered Load**	**Street Lighting**	**Embedded Distributor**
Deferral and Variance Account Rate Rider, Variable	$ (0.0003)	$ 0.0001	$ (0.0847)	$ (0.2424)	$ (0.0008)	$ (0.1640)	$ 1.1125
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

KWHI notes that the Direct Benefit Model calculates a direct benefit of only $947 on the capital portion of $117,985 (see Appendix 2-FB of the evidence). The rider above assumes that there is only a one year recovery for costs. Assuming this, the amount in the Renewable Connection - Capital line is actually $7,079. This represents the direct benefit component on the $117,985 capital amount discussed above.

The $7,079 is 6% of $117,985. Since it is assumed there is only a one year recovery period on the direct benefit component of account 1531, $7,079 has been included the rate rider table above in order to collect this capital amount in one year.

End of Board Staff Exhibit Two Interrogatories

Energy Probe Exhibit Two Interrogatories

2-Energy Probe-4

Ref: Exhibit 2, Tab 1, Schedule 2

a) How many months of actual data for 2013 are included in the figures provided in Table 2-2?

Answer: Since KWHI is applying for rates effective January 1, 2014, the 2013 forecast amounts were completely based on budgeted figures and not actual amounts. The budgets were generated in January 2013 before actuals had been incurred. The budgets were passed by our Board of Directors in May 2013 without actuals.

b) Please provide an updated Table 2-2 that reflects the most recent year-to-date information available for 2013, along with the most current projection for the remainder of the bridge year and any changes that may result in the 2014 test year as a result of the updated 2013 figures.

Answer: See updated table below. Note that the working capital allowance prior to 2014 was calculated at 15% of the cost of power and distribution expenses. For 2014, the working capital allowance is calculated at 13% of the cost of power and distribution expenses.

Rate Base Calculations 2009 Actual through 2014 Test

	2009	2010 Board Approved	2010	2011	2012	2013 Bridge	2014 Test
Distribution Expenses	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Distribution Expenses - Operation	2,815,696	3,051,200	2,824,720	3,258,635	4,821,308	5,518,900	5,642,000
Distribution Expenses - Maintenance	3,953,941	4,761,500	4,069,611	4,856,219	5,226,753	5,318,400	5,619,400
Billing and Collecting	2,883,410	3,003,200	2,700,114	2,919,903	3,514,152	3,493,200	3,933,800
Community Relations	227,140	209,400	212,185	198,223	164,909	256,675	237,300
Administrative and General Expenses	2,323,216	2,911,200	2,464,329	2,444,036	2,663,711	2,930,400	3,090,700
Taxes Other than Income Taxes	258,390	410,656	390,054	371,636	352,736	376,000	394,800
Less: Non-Labour Inflation		-54,997					
Total Eligible Distribution Expenses	**12,461,793**	**14,292,159**	**12,661,011**	**14,048,651**	**16,743,569**	**17,893,575**	**18,918,000**
Power Supply Expenses	143,134,762	139,152,168	156,940,481	163,084,890	170,281,848	186,238,810	183,214,980
Total Working Capital Expenses	**155,596,554**	**153,444,327**	**169,601,492**	**177,133,541**	**187,025,417**	**204,132,385**	**202,132,980**
Working Capital Allowance	23,339,483	23,016,649	25,440,224	26,570,031	28,053,813	30,619,858	26,277,287

	2009	2010 Board Approved	2010	2011	2012	2013 Bridge	2014 Test
Fixed Assets Opening Balance	131,028,265	130,822,048	131,582,065	143,352,364	152,037,099	163,614,013	179,522,061
Fixed Assets Closing Balance	131,582,065	146,377,220	143,352,364	152,037,099	163,614,013	179,522,061	189,014,062
Average Fixed Asset Balance	**131,305,165**	**138,599,634**	**137,467,215**	**147,694,732**	**157,825,556**	**171,568,037**	**184,268,062**
Working Capital Allowance	23,339,483	23,016,649	25,440,224	26,570,031	28,053,813	30,619,858	26,277,287
Rate Base	**154,644,648**	**161,616,283**	**162,907,438**	**174,264,763**	**185,879,369**	**202,187,895**	**210,545,349**
Regulated Rate of Return	7.20%	7.31%	7.31%	7.31%	7.31%	7.31%	5.98%
Regulated Return on Capital	**11,134,415**	**11,814,150**	**11,908,534**	**12,738,754**	**13,587,782**	**14,779,935**	**12,594,823**
Deemed Interest Expense	5,567,207	5,466,469	5,489,981	5,872,723	6,264,135	6,813,732	5,047,775
Deemed Return on Equity	5,567,207	6,367,682	6,418,553	6,866,032	7,323,647	7,966,203	7,562,789

2-Energy Probe-5

Ref: Exhibit 2, Tab 1, Schedule 2

The variance explanation for Account 1920 shown on pages 33 and 34 reflect four projects that total $170,000 out of the variance of $360,000. What is the remaining $190,000 related to?

Answer: $180,000 of the $190,000 should have been classified as software. The remaining $10K is for Miscellaneous Capital projects. This has been corrected in the Fixed Asset Continuity Schedule for 2014.

2-Energy Probe-6

Ref: Exhibit 2, Tab 2, Schedule 1

a) Please provide a copy of the most recent available monthly capital expenditure report that compares actual costs compared to budget as noted on page 1.

Answer: See table below. Forecasted 2013 capital expenditures have been updated and variances identified.

2013 Capital Expenditures

OEB	Description	August Actual 2013	Budget 2013	YTD Variance from Original 2013	Updated Forecast Bridge 2013	Updated Variance 2013
1808	Buildings and Fixtures	-	-	-		-
	Structure	76,115	33,100	43,015	76,100	43,000
1815	Transformer Station Equipment			-		-
	Switch Gear & Steel Structures	736,406	636,100	100,306	736,400	100,300
	Transformers & Grounding System	789,907	1,799,900	(1,009,993)	1,370,000	(429,900)
	Protection & Control Devices	59,521	263,300	(203,779)	59,500	(203,800)
	DC System			-		-
	Relays - P&C Devices/SCADA Equipment	167,955	133,400	34,555	590,000	456,600
1820	Distribution Station Equipment			-		-
	Relays - P&C Devices/SCADA Equipment	84,478		84,478	84,500	84,500
1830	OH - Poles, Towers and Fixtures	1,830,450	2,737,300	(906,850)	2,631,000	(106,300)
1835	OH - Conductors and Devices			-		-
	O/H Conductors	1,232,554	1,646,370	(413,816)	1,781,000	134,630
	O/H Devices	136,956	182,930	(45,974)	198,000	15,070
1840	UG - Conduit and Ductwork	1,314,199	3,272,900	(1,958,701)	2,361,000	(911,900)
1845	UG - Conductors and Cables			-		-
	PILC Cable	272,268		272,268	334,000	334,000
	U/G Cable	1,328,124	2,077,830	(749,706)	2,168,000	90,170
	U/G Devices	(18,721)	230,870	(249,591)	278,000	47,130
1850	Line Transformers			-		-
	OH Transformers	567,227	792,100	(224,873)	854,000	61,900
	Network Transformers	153,495	255,900	(102,405)	165,000	(90,900)
	Network Vault	27,063	85,400	(58,337)	33,000	(52,400)
	Network Protectors	126,664		126,664	132,000	132,000
	UG Transformers	712,908	224,200	488,708	750,000	525,800
	Submersible Transformers	200,413	1,319,100	(1,118,687)	563,000	(756,100)
	Transformer Foundations	24,323	386,300	(361,977)	270,000	(116,300)
1855	Services			-		-
	O/H Services	411,561	359,600	51,961	604,000	244,400
	U/G Services	957,763	1,912,100	(954,337)	1,706,000	(206,100)
1860	Meters	477,814	690,000	(212,186)	713,000	23,000
1908	Buildings and Fixtures			-		-
	Structure	1,380,210	1,086,100	294,110	1,766,200	680,100
	Roof & Other		60,900	(60,900)	187,400	126,500
1915	Office Equipment	50,284	90,000	(39,716)	90,000	-
1920	Computer Hardware	41,297	398,000	(356,703)	337,300	(60,700)
1925	Computer Software	130,575	341,000	(210,425)	400,200	59,200
1930	Transportation Equipment	640,590	890,000	(249,410)	1,391,000	501,000
1935	Stores Equipment		-	-		-
1940	Tools, Shop and Garage Equipment	55,206	88,400	(33,194)	68,800	(19,600)
1945	Measurement and Testing Equipment	9,406	-	9,406	9,400	9,400
1960	Miscellaneous Equipment	10,154	-	10,154	10,200	10,200
CAPITAL EXPENDITURES		**13,987,166**	**21,993,100**	**(8,005,934)**	**22,718,000**	724,900

Note that 1908 – Buildings & Fixtures and 1830 – Transportation Equipment forecasts have been increased due to delays in 2012 that carried over into 2013. These delays were not anticipated when the forecast was first created.

c) Has the capital budget forecast for 2014 been reviewed and approved by KWHI's Board of Directors? If not, when will this review and approval take place?

Answer: 2014 figures have not yet been approved by KWHI's Board of Directors. KWHI presents its forecasted capital budget for 2013 and 2014 original capital budget to its Board of Directors at its December 6, 2013 Board meeting.

2-Energy Probe-7

Ref: Exhibit 2, Tab 2, Schedule 1, Attachment 1

a) Has KWHI made any changes to its capitalization policy from that used to set rates in the last cost of service application for 2010 rates, other than the changes related to MIFRS/Modified CGAAP? If yes, please provide details.

Answer: No

b) Did KWHI make any changes to its depreciation rates from those used to determine the Board approved 2010 revenue requirement prior to the adoption of the modified CGAAP rates in 2012? If yes, please provide details.

Answer: No

c) Has KWHI made any changes to the modified CGAAP depreciation rates that were adopted in 2012 in 2013 or forecast for 2014? If yes, please provide details.

Answer: No

d) At page 4, the evidence indicates that full amortization is recorded in the year of acquisition and none in the year of disposal, except for readily identified assets, which are amortized on a monthly basis. Please confirm that this was the same methodology used to calculate the depreciation expense included in the 2012 Board approved revenue requirement. If this cannot be confirmed, please explain any differences in the methodology used for the 2010 test year and that used for actual 2010 through 2012, and forecasts for 2013 and 2014.

Answer: Confirmed. KWHI's 2010 Board approved revenue requirement assumed the half-year rule for additions made in the Test Year 2010. For its own internal purposes, KWHI continues to use the purchase date for its identifiable assets as the beginning date for amortization calculations and a full year of amortization in the year of acquisition for its pooled assets.

2-Energy Probe-8

Ref: Exhibit 2, Tab 2, Schedule 3

a) Has KWHI used the half year depreciation rule for accounts 1915 through 1960 which are mainly readily identified assets and are amortized on a monthly basis for financial accounting?

Answer: Yes, KWHI has used the half year depreciation rules for accounts 1915 through 1960 for 2014. It has not been used for 2013.

b) Is KWHI proposing to change the depreciation expense recorded for financial purposes to match the half year rule used for regulatory purposes? If not, why not?

Answer: No, KWHI is not proposing any changes to its depreciation expense policies. KWHI's depreciation methods are in accordance with the Board's filing requirements that require the half year rule to be used in the Test Year.

2-Energy Probe-9

Ref: Exhibit 2, Tab 3, Schedule 3, Attachment 1

a) Please explain why the disposals from accumulated depreciation shown for Account 1860 (Meters) in the 2011 fixed asset continuity schedule is larger than the disposals shown for gross assets.

Answer: For KWHI the meter account is showing the balance for the stranded meters, not smart meters. In 2011, there was an accumulated catch-up done for depreciation on the stranded meters of $201,607.

b) Please explain what assets are included in Account 1995 (OEB Clearing Account) beginning in 2012.

Answer: Contributed capital received on FIT and microFIT meter capital.

c) Please explain the disposal of $72,814 in accumulated depreciation in Account 1850 (Line Transformers - Overhead) in the 2012 fixed asset continuity schedule while there is no corresponding disposal shown for gross assets.

Answer: In 2012, transformers were classified between inventory and capital assets. Some inventory items had been used and needed to have the appropriate net book value transferred to inventory as they had been depreciated prior to them being transferred to inventory. This adjustment is a one- time adjustment to reflect the proper allocation of transformers between inventory and assets, reflecting the true net book value, and not historical cost.

d) Please explain the disposal of $36,631 in gross assets without any corresponding adjustment to accumulated depreciation in Account 1915 (Office Furniture and Equipment (10 years)) in the 2012 fixed asset continuity schedule.

Answer: The $36,631 is a transfer to assets not yet in service. These assets are for purchases of office furniture that has not yet been deployed by KWHI.

e) Please explain why there are no disposals of gross assets or accumulated depreciation, other than for Account 1930 (Transportation Equipment) shown in the continuity schedules for 2013 and 2014 (see part (f) below). Is this because the assets expected to be disposed of are all forecast to be fully depreciated?

Answer: Yes, KWHI continues to pool its major assets and they are written off at the end of service life. As for identifiable assets, KWHI rarely writes off assets prior to them being fully depreciated as it uses its assets to the end of their service lives where possible.

Due to extending the life of most assets due to the change in accounting policy adopted in 2012, most assets will not be fully depreciated in 2013 and 2014. Therefore there are no disposals of fully depreciated assets in 2013 and 2014

f) Please explain the disposal of meters in Account 1860 in the 2014 continuity schedule that are not fully depreciated.

Answer: In the absence of a transfers column in the continuity schedule, the addition of the meter capital from account 1531 requested through Exhibit 9 to be transferred to capital was added to the disposals column. This meter capital has been put through the direct benefits calculation and will be removed from the Fixed Assets Continuity Schedule.

g) The 2014 test year continuity schedule shows a reduction in the depreciation expense of $643,000 for fully allocated depreciation associated with transportation equipment. How much of this amount has been capitalized and how much has been included in OM&A expenses?

Answer: Approximately $378,000 will be OM&A and the remainder will be capitalized. This is based on a historical split of capital versus OM&A expenses. The majority of vehicle depreciation ($578,000) is burdened, and the historical split for vehicle overhead is 46% capital 54% maintenance.

h) Please explain why KWHI has included additions to computer hardware in CCA Class 10 in both 2013 and 2014. Please confirm that CCA Class 50 is to be used for computer hardware acquired after March, 2007.

Answer: Not confirmed. KWHI's computer hardware were classified to CCA Class 50. See Exhibit 4, Tab 8 Schedule 3.

2-Energy Probe-10

Ref: Exhibit 2, Tab 3, Schedule 3, Attachment 1

a) Please provide an updated fixed asset continuity schedule for 2013 that reflects the most recent actual capital expenditures to date in 2013 along **with the most** current projection for the remainder of 2013, consistent with the response to 2-Energy Probe-4.

Answer: See updated table for 2013 below:

Fixed Asset Continuity Schedule (Distribution & Operations)
CGAAP
as at December 31, 2013

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	2,339,958			2,339,958					2,339,958
1806	Land Rights	265,449			265,449	255,220	2,700		257,920	7,528
1808	Buildings and Fixtures									
1808	Buildings	9,087,934	543,000		9,630,934	2,170,106	197,300		2,367,406	7,263,528
1808	Roof	174,755			174,755	57,640	17,100		74,740	100,014
1810	Leasehold Improvements									
1815	Transformer Station Equipment - Normally Primary above 50 kV									
1815	Equipment - 50 Years	22,055,752	800,300		22,856,052	6,709,539	406,400		7,115,939	15,740,113
1815	Equipment - 40 Years	34,362,744	570,100		34,932,844	10,725,390	852,100		11,577,490	23,355,354
1815	Equipment - 25 Years	1,296,762	59,500		1,356,262	504,279	87,300		591,579	764,683
1815	Equipment - 20 Years	596,650			596,650	246,395	48,500		294,895	301,755
1815	Equipment - 15 Years	1,576,379	590,000		2,166,379	702,529	188,400		890,929	1,275,450
1820	Distribution Station Equipment - Normally Primary below 50 kV									
1820	Equipment - 50 Years	1,051,479			1,051,479	771,375	8,800		780,175	271,304
1820	Equipment - 40 Years	1,647,187			1,647,187	1,127,652	25,500		1,153,152	494,035
1820	Equipment - 25 Years	54,498			54,498	39,240	2,800		42,040	12,458
1820	Equipment - 20 Years	22,217			22,217	17,740	1,100		18,840	3,377
1820	Equipment - 15 Years	61,877	147,500		209,377	49,917	11,700		61,617	147,760
1825	Storage Battery Equipment									
1830	Poles, Tow ers and Fixtures	32,232,148	2,612,000		34,844,148	13,216,539	664,300		13,880,839	20,963,309
1835	Overhead Conductors and Devices									
1835	O/H Conductors	29,870,042	1,771,100		31,641,142	14,012,524	340,200		14,352,724	17,288,418
1835	O/H Devices	3,270,316	196,900		3,467,216	1,577,351	59,800		1,637,151	1,830,065
1835	Voltage Regulators	271,849			271,849	116,895	8,200		125,095	146,754
1835	Capacitor Banks	798,092			798,092	211,920	31,900		243,820	554,272
1840	Underground Conduit	23,815,908	2,280,000		26,095,908	9,785,064	309,900		10,094,964	16,000,944
1845	Underground Conductors and Devices									
1845	PILC	521,811	334,000		855,811	44,335	13,900		58,235	797,576
1845	U/G Cables	35,192,043	2,166,800		37,358,843	18,059,559	652,900		18,712,459	18,646,384
1845	U/G Devices	3,810,828	277,800		4,088,628	2,004,133	71,000		2,075,133	2,013,495
1850	Line Transformers									
1850	Overhead	39,170,598	850,200		40,020,798	22,990,586	603,300		23,593,886	16,426,912
1850	Netw ork Transformer	241,144	165,000		406,144	87,626	8,400		96,026	310,118
1850	Vault	2,629	33,000		35,629	44	21,200		21,244	14,385
1850	Roof	699,521			699,521	222,808	600		223,408	476,113
1850	Netw ork Protectors	201,676	132,000		333,676	7,200	8,200		15,400	318,276
1850	Padmount	5,746,508	646,400		6,392,908	1,164,736	147,700		1,312,436	5,080,472
1850	Submersible	4,813,188	551,000		5,364,188	981,058	172,300		1,153,358	4,210,830
1850	Foundation	2,214,385	270,000		2,484,385	400,374	35,400		435,774	2,048,611
1855	Services									
1855	Overhead	3,793,225	585,000		4,378,225	1,529,278	52,900		1,582,178	2,796,047
1855	Underground	40,156,132	1,592,000		41,748,132	16,327,860	809,100		17,136,960	24,611,172
1860	Meters	14,312,474	713,000		15,025,474	3,017,594	919,100		3,936,694	11,088,779
1860	Smart Meters									
1905	Land	1,395,300			1,395,300					1,395,300
1906	Land Rights									
1908	Buildings and Fixtures									
1908	Buildings	7,888,171	6,280,100		14,168,271	2,772,973	303,200		3,076,173	11,092,098
1908	Roof	2,386,887	186,500		2,573,387	1,065,928	255,700		1,321,628	1,251,758
1910	Leasehold Improvements									
1915	Office Furniture and Equipment	1,146,612	126,600		1,273,212	837,451	61,400		898,851	374,360
1920	Computer Equipment - Hardw are	2,869,446	337,300		3,206,746	2,289,302	169,000		2,458,302	748,444
1925	Computer Softw are	4,111,540	400,200		4,511,740	3,108,158	477,800		3,585,958	925,783
1930	Transportation Equipment	8,537,468	1,625,200	400,000	9,762,668	5,786,302	560,750	400,000	5,947,052	3,815,617
1935	Stores Equipment	64,072			64,072	46,100	4,000		50,100	13,972
1940	Tools, Shop and Garage Equipment	842,723	68,800		911,523	506,966	63,200		570,166	341,358
1945	Measurement and Testing Equipment	963,168	9,400		972,568	736,501	34,100		770,601	201,966
1950	Pow er Operated Equipment	837,763			837,763	534,588	54,600		589,188	248,575
1955	Communication Equipment	869,836			869,836	386,602	89,900		476,502	393,333
1955	Communication Equipment Meters									
1960	Miscellaneous Equipment	98,856	10,200		109,056	72,817	14,700		87,517	21,539
1970	Load Management Controls - Customer Premises									
1975	Load Management Controls - Utility Premises									
1980	System Supervisory Equipment	1,566,480			1,566,480	1,547,330	4,100		1,551,430	15,049
1985	Sentinel Lighting Rentals									
1990	Other Tangible Property									
1995	Contributions and Grants									
1995	Poles, Tow ers and Fixtures	(2,746,575)	(328,800)		(3,075,375)	(582,116)	(70,700)		(652,816)	(2,422,559)
1995	O/H Conductors	(2,243,429)	(226,200)		(2,469,629)	(424,479)	(38,100)		(462,579)	(2,007,050)
1995	O/H Devices	(249,270)	(25,100)		(274,370)	(47,726)	(5,000)		(52,726)	(221,644)
1995	O/H Services	(1,611,374)	(33,900)		(1,645,274)	(511,210)	(32,700)		(543,910)	(1,101,364)
1995	U/G Trenching & Ductw ork	(8,549,985)	(637,000)		(9,186,985)	(2,042,238)	(131,800)		(2,174,038)	(7,012,947)
1995	U/G Cable	(4,504,692)	(498,100)		(5,002,792)	(888,848)	(114,500)		(1,003,348)	(3,999,444)
1995	U/G Devices	(450,350)	(55,300)		(505,650)	(99,671)	(11,500)		(111,171)	(394,479)
1995	O/H Transformer	(3,675,837)			(3,675,837)	(982,880)	(86,400)		(1,069,280)	(2,606,557)
1995	U/G Padmount Transformer	(2,912,652)	(99,600)		(3,012,252)	(718,331)	(72,600)		(790,931)	(2,221,320)
1995	U/G Submersible Transformer	(2,747,208)	(232,300)		(2,979,508)	(664,918)	(74,700)		(739,618)	(2,239,890)
1995	U/G Services	(17,878,570)	(1,041,600)		(18,920,170)	(5,030,281)	(409,000)		(5,439,281)	(13,480,889)
1995	Transformer Foundation	(1,488,302)	(68,100)		(1,556,402)	(284,894)	(33,600)		(318,494)	(1,237,908)
1995	Meters	(311,788)	(40,000)		(351,788)	(73,125)	(28,800)		(101,925)	(249,863)
1995	OEB Clearing	163,900	40,000		203,900	11,526	13,802		25,328	178,572
	Total before Work in Process	**300,100,348**	**23,684,900**	**400,000**	**323,385,248**	**136,486,334**	**7,776,852**	**400,000**	**143,863,186**	**179,522,061**
2070	Other Utility Plant	270,820	(270,820)		(0)					(0)
	Work in Process	8,679,865	(3,942,065)		4,737,800					4,737,800
	Total after Work in Process	**309,051,033**	**19,472,015**	**400,000**	**328,123,048**	**136,486,334**	**7,776,852**	**400,000**	**143,863,186**	**184,259,861**

b) Please provide an updated fixed asset continuity schedule for 2014 that reflects the changes noted in part (a) above and is consistent with the response to 2-Energy Probe-4.

Answer: See updated table for 2014 below:

Fixed Asset Continuity Schedule (Distribution & Operations)
CGAAP
as at December 31, 2014

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	2,339,958			2,339,958					2,339,958
1806	Land Rights	265,449			265,449	257,920	2,700		260,620	4,828
1808	Buildings and Fixtures									
1808	Buildings	9,630,934	158,000		9,788,934	2,367,406	197,300		2,564,706	7,224,228
1808	Roof	174,755	3,200		177,955	74,740	12,700		87,440	90,514
1815	Transformer Station Equipment - Normally Primary above 50 kV									
1815	Equipment - 50 Years	22,856,052	650,000		23,506,052	7,115,939	411,100		7,527,039	15,979,013
1815	Equipment - 40 Years	34,932,844	1,390,000		36,322,844	11,577,490	881,000		12,458,490	23,864,354
1815	Equipment - 25 Years	1,356,262			1,356,262	591,579	87,300		678,879	677,383
1815	Equipment - 20 Years	596,650			596,650	294,895	41,500		336,395	260,255
1815	Equipment - 15 Years	2,166,379			2,166,379	890,929	146,000		1,036,929	1,129,450
1810	Leasehold Improvements									
1820	Distribution Station Equipment - Normally Primary below 50 kV									
1820	Equipment - 50 Years	1,051,479			1,051,479	780,175	8,800		788,975	262,504
1820	Equipment - 40 Years	1,647,187			1,647,187	1,153,152	25,500		1,178,652	468,535
1820	Equipment - 25 Years	54,498			54,498	42,040	2,200		44,240	10,258
1820	Equipment - 20 Years	22,217			22,217	18,840	1,100		19,940	2,277
1820	Equipment - 15 Years	209,377			209,377	61,617	6,000		67,617	141,760
1825	Storage Battery Equipment									
1830	Poles, Tow ers and Fixtures	34,844,148	2,768,400		37,612,548	13,880,839	703,585		14,584,424	23,028,124
1835	Overhead Conductors and Devices									
1835	O/H Conductors	31,641,142	1,997,100		33,638,242	14,352,724	354,573		14,707,297	18,930,945
1835	O/H Devices	3,467,216	221,900		3,689,116	1,637,151	63,297		1,700,448	1,988,668
1835	Voltage Regulators	271,849			271,849	125,095	8,200		133,295	138,554
1835	Capacitor Banks	798,092			798,092	243,820	31,900		275,720	522,372
1840	Underground Conduit	26,095,908	2,820,500		28,916,408	10,094,964	348,575		10,443,539	18,472,869
1845	Underground Conductors and Devices									
1845	PILC	855,811	700		856,511	58,235	8,300		66,535	789,976
1845	U/G Cables	37,358,843	2,359,600		39,718,443	18,712,459	680,198		19,392,657	20,325,786
1845	U/G Devices	4,088,628	262,200		4,350,828	2,075,133	73,100		2,148,233	2,202,595
1850	Line Transformers									
1850	Overhead	40,020,798	820,800		40,841,598	23,593,886	611,983		24,205,869	16,635,729
1850	Netw ork Transformer	406,144	192,100		598,244	96,026	13,000		109,026	489,218
1850	Vault	35,629			35,629	21,244	1,500		22,744	12,885
1850	Roof	699,521			699,521	223,408	20,900		244,308	455,213
1850	Netw ork Protectors	333,676	7,800		341,476	15,400	4,900		20,300	321,176
1850	Padmount	6,392,908	463,000		6,855,908	1,312,436	140,360		1,452,796	5,403,112
1850	Submersible	5,364,188	1,097,700		6,461,888	1,153,358	215,856		1,369,214	5,092,674
1850	Foundation	2,484,385	324,900		2,809,285	435,774	40,125		475,899	2,333,386
1855	Services									
1855	Overhead	4,378,225	538,500		4,916,725	1,582,178	85,775		1,667,953	3,248,772
1855	Underground	41,748,132	2,525,500		44,273,632	17,136,960	813,361		17,950,321	26,323,311
1860	Meters	15,025,474	612,000		15,637,474	3,936,694	928,842		4,865,536	10,771,937
1860	Smart Meters									
1905	Land	1,395,300			1,395,300					1,395,300
1906	Land Rights									
1908	Buildings and Fixtures									
1908	Buildings	14,168,271	1,350,000		15,518,271	3,076,173	309,400		3,385,573	12,132,698
1908	Roof	2,573,387			2,573,387	1,321,628	243,200		1,564,828	1,008,558
1910	Leasehold Improvements									
1915	Office Furniture and Equipment	1,273,212	70,000		1,343,212	898,851	75,800		974,651	368,560
1920	Computer Equipment - Hardw are	3,206,746	180,000		3,386,746	2,458,302	191,500		2,649,802	736,944
1925	Computer Softw are	4,511,740	540,000		5,051,740	3,585,958	545,300		4,131,258	920,483
1930	Transportation Equipment	9,762,668	920,000	400,000	10,282,668	5,947,052	705,600	400,000	6,252,652	4,030,017
1935	Stores Equipment	64,072			64,072	50,100	4,000		54,100	9,972
1940	Tools, Shop and Garage Equipment	911,523	90,000		1,001,523	570,166	72,200		642,366	359,158
1945	Measurement and Testing Equipment	972,568			972,568	770,601	34,100		804,701	167,866
1950	Pow er Operated Equipment	837,763			837,763	589,188	54,600		643,788	193,975
1955	Communication Equipment	869,836			869,836	476,502	89,800		566,302	303,533
1960	Miscellaneous Equipment	109,056			109,056	87,517	11,300		98,817	10,239
1970	Load Management Controls - Customer Premises									
1975	Load Management Controls - Utility Premises									
1980	System Supervisory Equipment	1,566,480			1,566,480	1,551,430	4,100		1,555,530	10,949
1985	Sentinel Lighting Rentals									
1990	Other Tangible Property									
1995	Contributions and Grants									
1995	Poles, Tow ers and Fixtures	(3,075,375)	(500,500)		(3,575,875)	(652,816)	(77,000)		(729,816)	(2,846,059)
1995	O/H Conductors	(2,469,629)	(411,840)		(2,881,469)	(462,579)	(41,500)		(504,079)	(2,377,390)
1995	O/H Devices	(274,370)	(45,760)		(320,130)	(52,726)	(5,600)		(58,326)	(261,804)
1995	O/H Services	(1,645,274)	(78,650)		(1,723,924)	(543,910)	(33,400)		(577,310)	(1,146,614)
1995	U/G Trenching & Ductw ork	(9,186,985)	(815,625)		(10,002,610)	(2,174,038)	(138,600)		(2,312,638)	(7,689,972)
1995	U/G Cable	(5,002,792)	(700,583)		(5,703,375)	(1,003,348)	(123,300)		(1,126,648)	(4,576,727)
1995	U/G Devices	(505,650)	(77,843)		(583,493)	(111,171)	(12,400)		(123,571)	(459,922)
1995	O/H Transformer	(3,675,837)			(3,675,837)	(1,069,280)	(86,400)		(1,155,680)	(2,520,157)
1995	U/G Padmount Transformer	(3,012,252)	(134,868)		(3,147,120)	(790,931)	(74,300)		(865,231)	(2,281,888)
1995	U/G Submersible Transformer	(2,979,508)	(314,700)		(3,294,208)	(739,618)	(80,000)		(819,618)	(2,474,590)
1995	U/G Services	(18,920,170)	(1,537,000)		(20,457,170)	(5,439,281)	(428,200)		(5,867,481)	(14,589,689)
1995	Transformer Foundation	(1,556,402)	(92,200)		(1,648,602)	(318,494)	(34,400)		(352,894)	(1,295,708)
1995	Meters	(351,788)	(40,000)		(391,788)	(101,925)	(30,100)		(132,025)	(259,763)
1995	OEB Clearing	203,900	40,000		243,900	25,328	15,100		40,428	203,472
	Total before Work in Process	**323,385,248**	**17,654,331**	**400,000**	**340,639,579**	**143,863,186**	**8,162,330**	**400,000**	**151,625,516**	**189,014,062**
2070	Other Utility Plant	(0)			(0)					(0)
	Work in Process	4,737,800	(928,100)		3,809,700					3,809,700
	Total after Work in Process	**328,123,048**	**16,726,231**	**400,000**	**344,449,279**	**143,863,186**	**8,162,330**	**400,000**	**151,625,516**	**192,823,762**

2-Energy Probe-11

Ref: Exhibit 2, Tab 4, Schedule 1, Attachment 1

The schedules show that the Year End WIP for 2009 through 2013 range from about $3.8 million to $9.3 million and with an average over this period of approximately $6.2 million. The forecast year end WIP for 2014 is $3.8 million. Please explain why it is reasonable to assume that the test year WIP will be at the lower end of this historical range.

Answer: When estimating WIP for the year end 2014, several steps were taken. Starting with the opening WIP balance as at January 1st, 2013, the capital budget figures were then added. Then an analysis was performed to determine the average change in WIP for the last four years. This gave a year-end balance for 2013, and then 2014. However, KWHI has had some fairly large projects that are unique by year and will not continue going forward. At the end of 2012, for example, there was a fairly large balance related to the Service Centre renovation and addition ($4,545,711). This project was predicted to be completed in 2013 for an additional $1,100,000. The WIP balance going forward should therefore decline.

As well, there are some large TS projects that are on-going with estimated completion in 2014.

2-Energy Probe-12

Ref: Exhibit 2, Tab 4, Schedule 3

For each of the projects listed for 2013 (pages 65-79) that includes an expected completion date, please update the completion date, if applicable, to reflect work performed to date and the most current projection of when the project will be completed and placed in service. For any projects that are now expected to be completed beyond the end of 2013, please indicate the amount of expenditures forecast to be included in WIP at the end of the bridge year.

Answer: The following is a list of 2013 projects with updated completion dates to reflect work completed to date or project deferral. Projects with completion dates that are expected to remain the same (that is, completed as forecasted or to be completed as forecasted) are not listed here.

2013 TRANSFORMATION FACILITIES

5TS work – T99 Spare Transformer Rewind [page 67 – 68]

- **The project is now expected to be completed by March 2014 instead of October 2013 due to delays by the transformer repair facility.**
- **Forecasted expenditures to be included in WIP at end of 2013 : $718,000**

2013 POLE LINES

Relocations - Light Rail Transit (LRT) - [page 70]

- **The following projects will not be completed in 2013:**
  - **Hayward Ave. - this project is now expected to be initiated in 2014 and completed by end of 2014.**
  - **King St. W. – project scope has changed and the project is now expected to be initiated in 2015 and completed by end of 2015**
- **Forecasted expenditures to be included in WIP at end of 2013 : $0**

Vanier Drive (H/Way to Kipling Avenue) – [page 71]

- **This project was completed in May 2013 instead of December 2013.**

Ardelt Ave (Hanson to Ardelt Pl.) – [page 71]

- **This project was completed in August 2013 instead of December 2013.**

Huron Road (H1 ROW to Trussler Rd) – [page 71]

- **The project is now expected to be completed by June 2014 instead of December 2013.**
- **Forecasted expenditures to be included in WIP at end of 2013 : $98,000**

Oxford Street (Elizabeth St to X-Way) – [page 71]

- **This project was completed in April 2013 instead of December 2013**

2013 UNDERGROUND DUCTS AND CABLES

Halls Lane 2013 – [page 76]

- **Some of the work budgeted for the Halls Lane 2013 project will be carried forward to the 2014 budget year. The project is expected to be completed by June 2014 instead of December 2013.**
- **Forecasted expenditures to be included in WIP at end of 2013 : $60,000**

Relocations - Light Rail Transit (LRT) - [page 76]

- **The following projects will not be completed in 2013:**
  - **Rebuild pull boxes on Francis Street - this project is now expected to be initiated in 2014 and completed by end of 2014**
  - **Install PILC Cables - this project is now expected to be completed by July 2014**
- **Forecasted expenditures to be included in WIP at end of 2013 : $120,000**

2-Energy Probe-13

Ref: Exhibit 2, Tab 4, Schedule 5

How much of the OM&A smart meter related costs shown on page 3 ($653,091 O&M, $379,723 B&C and $51,649 Admin) are actually incurred in 2012 and how much was incurred in previous years?

Answer: **See table below. During the 2012 year end process, it was determined that the costs for Sensus metering were incorrectly allocated to operating accounts rather than billing & collecting.**

	2009	2010	2011	Apr-12		Dec-12	
Operations	55,514	50,985	245,228	301,363	653,091	(143,353)	509,737
Billing & Collecting	93,784	102,333	158,959	24,647	379,723	143,353	523,076
Admin	13,333	9,106	2,731	26,479	51,649	-	51,649
	162,631	162,424	406,919	352,490	1,084,463	-	1,084,463

2-Energy Probe-14

Ref: Exhibit 2, Tab 4, Schedule 6 &
Exhibit 2, Tab 3, Schedule 3, Attachment 1

a) Please explain the significant increase in the gross asset value of stranded meters shown in Tab 2-8 of Exhibit 2, Tab 4, Schedule 6 between 2009 and 2010.

Answer: **Table 2-8 reflects the stranded assets (meters) as at that time. KWHI began installing smart meters in late 2008. Most of the smart meters were installed in KWHI's territory during the years 2009 through 2011. The smart meter installs were complete (for the most part) by December 2011. As the number of smart meter installations went up, so did the number of stranded conventional meters.**

c) Please reconcile the this increase with the figures (including additions) shown for meters in the 2010 fixed asset continuity schedule in Exhibit 2, tab 3, Schedule 3, Attachment 1.

Answer: **The stranded meters were kept in rate base until 2012 when KWHI received its Smart Meter Decision from the OEB as per Board direction.**

The total meter capital on the 2010 fixed asset continuity schedule shows a balance of $11,847,412 as at December 31, 2010. This balance includes the stranded meter assets of $8,597,810 presented in Table 2-8. The balance of meter capital net of stranded assets was $3,249,602.

In addition, the total accumulated depreciation on the meter capital on the 2010 fixed asset continuity schedule shows a balance of $6,532,647 as at December 31, 2010. This balance includes the stranded meter assets of $4,709,662 presented in Table 2-8. The balance of accumulated depreciation on meter capital net of stranded assets was $1,822,985.

2-Energy Probe-15

Ref: Exhibit 2, Tab 5, Schedule 1

Please provide a Board file number with respect to the *"generic proceeding/consultation"* referred to in the Board's decision on page 2. Did KWHI participate in the process?

Answer: KWHI cannot find the reference to the Board file number but pasted the link to the letter below. KWHI did not participate in the development of the WCA.
http://www.ontarioenergyboard.ca/OEB/_Documents/2013EDR/Letter_WCA_for_2013_Filing_Requirements_20120412.pdf

2-Energy Probe-16

Ref: Exhibit 2, Tab 5, Schedule 1

The evidence indicates that KWHI plans to change its residential billing cycles from bi-monthly to monthly in the near future.

a) What other rate classes does KWHI currently bill on a bi-monthly basis?

Answer: It is KWHI's intent to move all bi-monthly billing to monthly billing which includes, residential, general service <50 and micro-fit accounts.

b) Is the movement of the residential billing cycles from bi-monthly to monthly taking place in 2013 or 2014?

Answer: KWHI has commenced the analysis and planning to move all bi-monthly billings to monthly. It is anticipated implementation will not occur until 2014.

c) What are the additional costs included in the 2014 revenue requirement associated with the movement of the residential billing cycle from bi-monthly to monthly billing?

Answer: The total cost included to move to monthly billing for 2014 is $200,000 for additional postage and office supplies. See 4-STAFF-20 c) for details.

d) Has KWHI made any changes associated with bad debt and/or collection expense as a result of the proposed move from bi-monthly to monthly billing? If yes, please provide details. If not, please explain why not.

Answer: KWHI has decreased the budget amount for bad debt by 21%. Other than costs such as paper and postage, KWHI does not foresee substantial decreases in collection expenses.

It should be noted that KWHI has increased its estimate for 2013 for bad debt expense to $187,000. This was KWHI's original estimate and a typo resulted in $147,000 being entered into its rate model. Waterloo Region has experienced a significant announcement that very well may affect KWHI's estimation of bad debt going forward. Blackberry recently announced lay-offs affecting potentially 10,000 direct and indirect jobs in the local area. Also, the OEB requirement to not collect security deposits for low income customers has increased KWHI's exposure to bad debts. Based on year-to-date results, KWHI estimates that an additional $3,000 should be added to 2014 for a total of $190,000. KWHI has not yet updated its rate model for this amount in 2014.

End of Energy Probe Exhibit Two Interrogatories

No School Energy Exhibit Two Interrogatories

VECC Exhibit Two Interrogatories

2.0-VECC – 2

Reference: Exhibit 2, Tab 5, Schedule 1

a) Please provide KWHI's reduction in working capital requirements that will result from moving from bi-monthly to monthly billing. If no reduction is contemplated please explain why.

Answer: Since KWHI did not complete a lead/lag study, KWHI is unable to determine the impact on working capital requirements resulting from moving to monthly billing from bi-monthly billing.

2.0-VECC – 3

Reference: Exhibit 2, Tab 4, Schedule 1

a) Please provide the annual capital expenditures (actual and forecast) for the years 2009 through 2018 for projects related to the distribution system line/voltage upgrade for the Wilmot Township distribution system.

Answer: A planning study performed in 1995 examined the future of the distribution system in Wilmot Township. The principle recommendations were that the 8.3 kV distribution system be gradually converted to 27.6 kV operation and that a 27.6 kV transformer station be constructed near the load centre. Benefits of voltage conversion include:

(i) Improved system efficiency (by reducing line losses).

(ii) Improve voltage regulation.
(iii) Future costs to expand distribution stations to accommodate load growth are avoided.
(iv) Future costs to maintain/rebuild distribution substations are avoided.
(v) Reduced ground currents and stray voltages.
(vi) Improved ability to connect distributed generation. Increasing the capacity of a distribution feeder increases the size of distributed generation site that can be connected to that feeder.

Pole Lines

Kitchener-Wilmot Hydro began the conversion to 27.6 kV in 1995. The voltage conversion strategy leverages the need to rebuild pole lines due to age/condition. If voltage conversion for any given section of line is deferred until the pole line is rebuilt, the cost of conversion is essentially the marginal cost of the insulation. The majority of voltage conversion will happen through the rebuild process. All lines constructed in Wilmot Township since 1995 have been constructed with 27.6 kV insulation. However, some expenditures will be required that are not covered by end-of-life rebuilds. One example is the replacement of insulators on poles that are still in good condition. Another example is the replacement of switches, lighting arresters and transformers on lines that are already insulated for 27.6 kV. Please see Exhibit 2, Tab 4, Schedule 3 and Exhibit 2, Tab 4, Schedule 4 for a more thorough discussion of voltage conversion.

The following is a summary of the total costs for converting the voltage on pole lines where the pole lines were not rebuilt for some other drivers, mostly end of life rebuilds:

Year	Total Cost	Actual/Forecast
2009	$ 0	Actual
2010	$ 0	Actual
2011	$ 156,466	Actual
2012	$ 39,761	Actual
2013	$ 430,000	Budget
2014	$ 550,000	Forecast
2015	$ 500,000	Forecast
2016	$ 500,000	Forecast
2017	$ 500,000	Forecast
2018	$ 500,000	Forecast

Underground Cables

On December 31, 2012, there were 67.3 kilometres of single phase URD primary cable installed in the 8.3 kV distribution system. All of it must be converted to 27.6 kV operation when the upstream pole lines are converted. All URD primary cable installed in the 8.3 kV distribution system since 1995 (approximately 43.2 kilometres) is insulated for 27.6 operation. This cable can be converted relatively inexpensively by replacing the switches, lightning arresters, transformers and elbow connectors. The remainder of the cable (approximately 24.1 kilometres) must be replaced.

Fortunately, this is also the oldest cable and would eventually have to be replaced due to age/condition. The timing of the underground conversion will mostly be driven by the schedule for rebuilding and converting the nearby pole lines. However, it is anticipated that the urban areas will be the last to be converted. As this is where most of the URD primary cable is installed, the primary cable is expected to be near the end of its useful life when it is replaced for voltage conversion. Please see Exhibit 2, Tab 4, Schedule 3 and Exhibit 2, Tab 4, Schedule 4 for a more thorough discussion of voltage conversion.

The following is a summary of the total costs for converting the voltage on underground cable systems where the cables were not replaced for some other drivers, mostly end of life rebuilds:

Year	Total Cost	Actual/Forecast
2009	$ 0	Actual
2010	$ 0	Actual
2011	$ 114,128	Actual
2012	$ 124,137	Actual
2013	$ 50,000	Budget
2014	$ 220,000	Forecast
2015	$ 100,000	Forecast
2016	$ 100,000	Forecast
2017	$ 100,000	Forecast
2018	$ 100,000	Forecast

Distribution Transformers

In keeping with KWHI's strategy of converting the voltage on pole lines and cables during replacements due to age and condition, expenditures for the replacement of transformers solely to facilitate voltage conversion are expected to be minimal. Consequently, KWHI's 10 Year Capital Expenditures Forecast did not allocate separate funding for this activity.

However, in 2012, 2013 and 2014 KWHI will convert the operating voltage of a number of pole lines and cables that had previously been insulated for 27.6 kV operation. The principal cost of these conversions is the replacement of the distribution transformers. The funding requirements were material enough to warrant breaking out in the Capital Budgets.

Year	Total Cost	Actual/Forecast
2009		Actual
2010		Actual
2011		Actual
2012	$ 255,689	Actual
2013	$ 75,000	Budget
2014	$ 100,000	Forecast
2015		Forecast
2016		Forecast

2017	**Forecast**
2018	**Forecast**

Notes:

1. **Based on expenditures year-to-date, KWHI now estimates that the 2013 expenditures for voltage conversion will exceed the combined budget for conversion of pole lines, underground cables and distribution transformers by approximately $86,000.**

b) For each year please provide separately any contributions in aid of construction that were provided or are expected for this project.

Answer: This is a KWHI capital only project and contributed capital is zero.

2.0-VECC – 4

Reference: Exhibit 2, Tab 2. Schedule 5

a) Please provide the capital contributions by USoA account for which it pertains for the years 2010 through 2014 (forecast).

Answer: See table below:

USoA	2010	2011	2012	2013	2014
1830	(414,898)	(103,096)	(600,093)	(328,800)	(500,500)
1835	(417,799)	(98,637)	(674,581)	(251,300)	(457,600)
1840	(509,048)	(529,585)	(1,079,357)	(637,000)	(815,625)
1845	(623,976)	(524,481)	(1,498,222)	(553,400)	(778,426)
1850	(705,419)	(556,502)	(1,076,350)	(400,000)	(2,078,768)
1855	(1,433,168)	(1,000,739)	263,259	(1,075,500)	(78,650)
1860	(765)	(9)	(15,555)	0	0
	(4,105,073)	**(2,813,049)**	**(4,680,899)**	**(3,246,000)**	**(4,709,569)**

2.0-VECC – 5

Reference: Exhibit 2, Tab 4, Schedule 3

a) Please provide an update to the 2013 spending for Roadway Modifications ($1,155,000). Please indicate the amount spent to-date, the amount anticipated to year-end and the amount committed capital contributions provided by the municipality and or other level of government.

Answer: The total forecast is unchanged at $1,155,000. 2013 Year to date spending for Roadway modifications is $735,601.27; 2013 year-end spending forecast is $419,398.73. The anticipated capital contributions for 2013 is $460,633.50

2.0-VECC – 6

Reference: Exhibit 2, Tab 4, Schedule 3

a) The capital budget for “Replacement of Pole Line Assets Due to Age/Condition” has increased significantly in each year since 2009 rising from $735K to $2,575K in 2014. Please explain the reasons for this.

Answer: KWHI formalized and documented its asset management practices in 2009 when it published its Asset Management Plan. At that time, the Asset Management Plan consisted of three interrelated documents. The Asset Management Strategy documents KWHI's asset maintenance and replacement practices. The Capital Expenditures Program examines KWHI's assets and identifies long term investments in the acquisition of new assets and replacement of aging assets. The 10 year Capital Expenditures Forecast establishes long term capital funding required to implement the Capital Expenditures Program and Asset Management Strategy.

A significant percentage of the poles in KWHI's distribution system were installed in the 1950's and 1960's and are approaching end-of-life for the first time. The Capital Expenditures Program identified this trend and observed that the number of end-of-life replacements must increase over time. The 10 year Capital Expenditures Forecast allocates funding for a gradual ramp-up in the expenditures for end-of-life pole replacements. These end of life replacements are described in various documents as "Replacement of Pole Line Assets Due to Age/Condition".

The 2013 Pole Replacement budget is $2,216,200. The main reason for the variance between the 2013 budget and the projection to December 31st is the deferral of two projects from 2013 budget year to 2014.

b) Please provide the budget for this type of project for 2015 through 2018.

Answer: The 10 year Capital Expenditure Forecast allocates the following funds for the "Replacement of Pole Line Assets Due to Age/Condition".

Year	Forecast
2015	$ 2,500,000
2016	$ 3,500,000
2017	$ 3,500,000
2018	$ 3,500,000

c) Please update the 2013 Pole Replacement budget to show actual spent to-date and (separately) projected year-end spending.

Answer: See table below:

Budget #	Budget Description	YTD Actual Aug. 31st	Projected Dec. 31st
03-13-04	Single-Phase Pole Line Rebuilds	394,000	480,000
03-13-07	Vanier Drive : H/Way to Kipling Avenue	173,000	173,000
03-13-08	Ardelt Ave - Hanson to Ardelt Pl.	207,000	210,000
03-13-09	Hanson Dr. - Homer Watson Blvd. to Hayward Ave.	143,000	150,000
03-13-10	Union St - Lancaster St. to Boehmer St.	0	0
03-13-12	Huron Rd - H1 ROW to Trussler Rd.	5,000	98,000
03-13-13	Oxford-Waterloo Rd: Sandhills Rd to End of 3-Ph Line	87,000	95,000
03-13-14	Oxford St - Elizabeth St to X-Way	176,000	176,000
03-13-15	Webster Rd - Manitou Dr to Wilson Ave	0	0
03-13-16	Wilmot Line - Berletts Rd to Cedar Grove	40,000	243,000
03-13-17	Cedar Grove Rd - Wilmot Line to end	22,000	100,000
	Total	**1,247,000**	**1,725,000**

2.0-VECC – 7

Reference: Exhibit 2, Tab 4, Schedule 3

a) There is a significant increase in the trend in capital spending after 2009. Please explain, in general terms, the reasons for this trend change.

Answer: The increase in capital expenditures after 2009 is primarily due to four factors:

1. <u>Replacement of Pole Line Assets Due to Age/Condition</u>

Reference: Exhibit 2, Tab 4, Schedule 2; and Exhibit 2, Tab 4, Schedule 4

KWHI formalized and documented its asset management practices in 2009 when it published its Asset Management Plan. At that time, the Asset Management Plan consisted of three interrelated documents. The Asset Management Strategy documents KWHI's asset maintenance and replacement practices. The Capital Expenditures Program examines KWHI's assets and identifies long term investments in the construction of new assets and replacement of aging assets. The 10 year Capital Expenditures Forecast establishes long term capital funding required to implement the Capital Expenditures Program and Asset Management Strategy.

A significant percentage of the poles in KWHI's distribution system were installed in the 1950's and 1960's and are approaching end-of-life for the first time. The Capital Expenditures Program identified this trend and observed that the number of end-of-life replacements must increase over time. The 10 year Capital Expenditures Forecast allocates funding for a gradual ramp-up in the expenditures. These end of life replacements are described in various documents as "Replacement of Pole Line Assets Due to Age/Condition".

2. Relocations Due to Roadway Modification Projects

Reference: Exhibit 2, Tab 4, Schedule 3

Municipalities are spending more money than ever upgrading roadways and replacing aging infrastructure. This has resulted in a dramatic increase in expenditures for the relocation of existing distribution system assets from $1M in 2009 to $5M in 2014. These expenditures are not discretionary.

3. Construction of Transformer Station #9

Reference: Exhibit 2, Tab 4, Schedule 3

The construction of a new transformer station is an infrequent event. Expenditures are typically lumpy and heavily loaded into the final years of the project after equipment has been delivered and accepted. KWHI constructed Transformer Station #9 in the period 2008 through 2010.

4. Renovation and Expansion of the Service Centre

Reference: Exhibit 2, Tab 4, Schedule 4

The Main Office (Administration) and Service Centre (Operations) facilities were constructed by the Corporation at 301 Victoria Street South, Kitchener in 1985 and 1988. In 1985, the Corporation served 51,605 customers in the City of Kitchener and Township of Wilmot. An expansion and renovation to the Service Centre was constructed in 2012 and 2013 to update 25 year old washroom and locker room facilities and to provide additional space for the Corporation's vehicle fleet in order to serve over 90,000 customers today or an increase of 75% since the facilities were first constructed.

2.0-VECC – 8

Reference: Exhibit 2, Tab 4, Schedule 4/Exhibit 4, Tab 3, Schedule 1 (2013 capital plan)

a) Are there any plans to move or relocate the administration office or service centre during the next 5 years?

Answer: No

2.0- VECC - 9
Reference: Exhibit 2, Tab 4, Schedule 5, Table 2.7

a) Please explain what the incremental labour costs of $360,000 in respect to incremental smart meter costs are for.

Answer: This is an incremental cost to account 5065 due to the completion of the Smart Meter Initiative. Previously labour costs associated with smart meters OM&A were included in account 1556. With the completion of the Smart Meter Initiative, the metering OM&A costs return to pre—Smart Meter Initiative levels and include labour costs for the daily maintenance of the AMI system to ensure reliable communication with the meters. This is accomplished through examining meter communication and read reports, tuning of meters to provide better communication performance and troubleshooting faulty meters and meters with faulty communication modules.

b) Is the $711,900 in incremental smart meter costs referred to in Table 2.7 net of any reduction in manual meter reading costs?

Answer: Yes

c) Please provide the amount paid for manual meter reading in the last full year (2009?) in which all meters were read manually.

Answer: Final full year of manual meter reading was 2010 and the amount paid was $200,787.

d) Please explain what "Software Escrow Fees" are and are for.

Answer: A copy of the source code of the hosted AMI System proprietary software is held in escrow by a third party, in KWHI's case, Iron Mountain Intellectual Property Management Inc. The AMI System provider deposits the software into the escrow account and in the event of bankruptcy of the AMI System provider; the Beneficiary (Kitchener-Wilmot Hydro) shall have continued rights to the software. "Software Escrow Fees" are the annual fees for holding the software and providing verification services on the software.

2.0 – VECC – 10
Reference: Exhibit 2, Tab 6, Schedule 2

a) Please provide the causes of service interruptions by category (see sample table below – or descriptors used by KWHI).

Description	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Scheduled				
Supply Loss				
Tree Contact				
Lightning				
Def. Equip.(other than pole)				
Pole Failure				
Weather				
Animals, Vehicle				
Unknown				
Total				

Answer: See Chart

Description	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Scheduled	196	241	183	167
Supply Loss	17	6	7	5
Tree Contact	47	55	27	50
Lightning	42	39	61	94
Def. Equip.(other than pole)	287	155	138	146
Pole Failure	0	2	1	2
Weather	107	33	50	24
Animals, Vehicle	199	171	112	180
Unknown	151	80	74	82
Total	1046	782	653	750

2.0-VECC – 11

Reference: Exhibit 2, Tab 4, Schedule 7 / Tab 7, Schedule 1

a) Please provide the total capital and OM&A Green Energy Plan related costs (separately) that will be incurred in 2013.

Answer: There will be no capital costs related to the Green Energy Plan in 2013. The OM&A costs related to renewable generation are limited to hiring a summer student in the summer and fall to manage the microFIT demand, plus the staff overtime spent for microFIT projects. These costs are forecast to be $34,350 in 2013.

b) Are any of the above costs included in the 2014 revenue requirement and used in the calculation of the proposed new rates?

Answer: No, all incremental OM&A costs have been excluded from the 2014 Revenue Requirement.

End of Exhibit Two Interrogatories

Board Staff Exhibit Three Interrogatories

Exhibit 3 – Operating Revenues

3-Staff-13 Ref: Exhibit 3/Tab 1/Schedule 2/Tables 3-2, 3-3 and 3-5

KWHI states that Table 3-5 provides the rate riders applied and not removed from distribution revenue, and identifies LRAM, SMDR and SMIRR as the complete list of these rate riders. Please explain whether KWHI has retained or removed the Smart Meter Funding Adder revenues from distribution revenue in Table 3-2. Further identify where these revenues are contained in Table 3-3 or Table 3-5. If they are not accounted for in either of these tables, please explain.

Answer: The Smart Meter Funding Adder (SMFA) revenue was not removed from gross distribution revenue in Table 3-2. The removal of this revenue is shown in Table 3-3 through reductions to the fixed charge. See table 3-2 below (2012 revenue dollars only):

Details of GrossThroughput Revenue

Revenues	2012 Actual
Throughput Revenue Gross ($)	44,345,833
Smart Meter Decision	(5,150,879)
Adjusted Gross Revenue	39,194,954
Fixed Charge	**16,050,496**
Residential	10,227,056
GS<50	2,431,407
GS>50	2,731,860
Large User	346,475
Street Lighting	225,336
USL	88,362
Variable Charge	**23,144,458**
On kWh	12,985,833
Residential (kWh)	10,114,713
GS<50 (kWh)	2,800,899
USL (kWh)	70,221
On kW	**10,158,625**
GS>50 (kW)	9,580,013
Large User (kW)	279,032
Street Lighting (kW)	243,251
Embedded Distributor	56,329

Total revenue after the Smart Meter Decision is $39,194,954.

Below are the fixed and variable rate riders (inclusive of the Smart Meter Funding Adders) that are included in Table 3-2 above and were outlined in Table 3-3. These must be removed from distribution revenue as they are/were regulatory assets. Total rate riders to be removed from distribution revenue for 2012 are $751,100.

Rate Riders Applied & Removed from Distribution Revenue

Rate Rider Type	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Fixed Charge	**757,128**	**1,027,313**	**1,639,408**	**1,022,123**
Residential	681,586	926,285	1,473,878	924,351
GS<50	53,667	89,144	146,944	100,829
GS>50	21,851	11,867	18,555	(3,078)
Large User	24	16	31	20
Street Lighting	-	-	-	-
USL	-	-	-	-
Variable Charge	**-**	**(1,720,040)**	**(2,374,480)**	**(271,022)**
On kWh	-	(873,047)	(1,842,566)	(1,057,275)
Residential (kWh)	-	(621,970)	(1,318,046)	(758,694)
GS<50 (kWh)	-	(247,312)	(517,115)	(293,998)
USL (kWh)	-	(3,765)	(7,406)	(4,583)
Total Rate Riders				**751,100**

Note that the Table 3-4 below (2012 revenue dollars only) shows the distribution revenue net of the rate riders that are supposed to be removed from distribution revenue:

Revenue	2012 Actual
Throughput Revenue ($) Net of Rate Riders	38,443,854
Fixed Charge	15,028,373
Residential	9,302,705
GS<50	2,330,578
GS>50	2,734,938
Large User	346,455
Street Lighting	225,336
USL	88,362
Variable Charge	**23,415,480**
On kWh	14,043,108
Residential (kWh)	10,873,407
GS<50 (kWh)	3,094,897
USL (kWh)	74,804
On kW	**9,372,373**
GS>50 (kW)	8,904,454
Large User (kW)	181,922
Street Lighting (kW)	229,669
Embedded Distributor	56,329

Based on the above, gross distribution revenues of $39,194,954 less $751,100 equal the amount reported above of $38,443,854.

Table 3-5 includes only the rate rider revenue which is not to be removed from distribution revenue for regulatory purposes (LRAM, SMDR, SMIRR). Table 3-4 is therefore the amounts that would be reported to the OEB.

3-Staff-14 Ref: Exhibit 3/Tab 1/Schedule 4, Exhibit 3/Tab 1/Schedule 5, and Appendix B – Loss of Large Use Customer

On page 5 of this Exhibit 3/Tab 1/Schedule 4, KWHI states that it "has manually adjusted for the loss of one of its Large Users who is ceasing operations in 2014. KWHI currently has two Large Users but there is certainty that one of the large user customers [is] closing down operations."
Appendix B to Exhibit 3 is a copy of a news release of the Maple Leafs Food plant closure by the end of 2014.

Documentation of how KWHI has adjusted the load forecast, specifically for the Large Use class which will have one remaining customer, is provided on pages 4 and 5 of Exhibit 3/Tab 1/Schedule 5.

KWHI states that it has adjusted the class consumption and peak demand to remove the Maple Leaf Foods' amount from 2014 in its entirety.

a) Given that the Maple Leaf Foods is still expected to be a customer of KWHI for at least part of the 2014 test year, how has KWHI accounted for the revenues that it will be receiving from this customer?

Answer: KWHI has removed all of the revenue applicable to Maple Leaf Foods from the load and revenue forecast for 2014.

b) What capital and operating costs has KWHI removed associated with distribution services that it provides to Maple Leaf Foods?

Answer: KWHI did not anticipate any capital requirements related to Maple Leaf Foods for 2014 and beyond and therefore no capital costs have been removed in the forecast. Operating costs directly related to Maple Leaf Foods are minimal as it is a Large Use customer and owns much of its own equipment. Operating costs related to KWHI-owned distribution plant will be unaffected as the facility will continue to be connection to the distribution grid until such time as a decision is made on the future of this site.

c) How has the loss of Maple Leaf Foods been taken into account in the Cost Allocation study and in the associated matters of rate design and proposed distribution rates?

Answer: The loss of the large use customer is reflected in the Cost Allocation model by using only one customer. Weightings were derived for Services and Billing and Collecting using appropriate weights for one customer. The Revenue is based on the forecast kW for the remaining customer.

3-Staff-15 Ref: Exhibit 3/Tab 1/Schedule 4 – CDM Variable

KWHI has included a CDM variable in its regression equation, with the estimated coefficient of the CDM variable being -3.88. KWHI describes the construction of the CDM variable on page 4 of the exhibit, and the data are contained in tab "CDM Activity" of the load forecast excel spreadsheet.

KWHI describes that a linear interpolation was used to interpolate the monthly values to sum to the reported annual OPA savings in each year. As a starting example, the 2005 CDM savings per the OPA reports are 292,583 in 2005. Board staff notes that, as documented in the OPA reports, the reported annualized savings for the year are estimated as if all programs were in effect the full year from January 1 to December 31.

It is reasonable to assume that the savings from the persistence of prior year CDM programs would be in effect for the full year. However, new CDM programs are implemented at various times in the year and hence will not have the full impact in the first year of implementation. In the absence of more specific information as to when CDM programs were launched and results implemented in a year, a half-year rule is used as an approximation to measure the real impact of CDM programs in their initial year.

This concept of the annualized versus the real impact on consumption would also apply to historical programs. In this case, the actual impact of 2005 CDM programs on 2005 consumption should 292,583/2 = 146,291.5 kWh. The monthly values in 2005 should be linearly interpolated from 0 such that the sum would equal the 146,291.5 kWh, not 292,583 kWh as constructed.

For 2006, the full annualized persistence of 2005 programs (i.e., 292,583 kWh) is assumed, and the incremental annualized savings for 2006 should be divided by 2 to reflect the half-year impact of the 2006 CDM programs in the first year, 2006.

a) Please prepare a CDM activity variable that reflects the half-year rule impact of CDM programs in the first year.

Answer: Complete, included in the live excel spreadsheet included.

b) Please re-run the regression model with this variable. Provide all regression statistics in the standard Microsoft Excel regression output format, and provide the regression model, including the construction of the CDM variable in this format.

Answer: Complete, included in the live excel spreadsheet included.

c) Please provide KWHI's views as to why the estimated coefficient from the regression model is 3.88 and why the the estimated CDM coefficient is greater than unity in value.

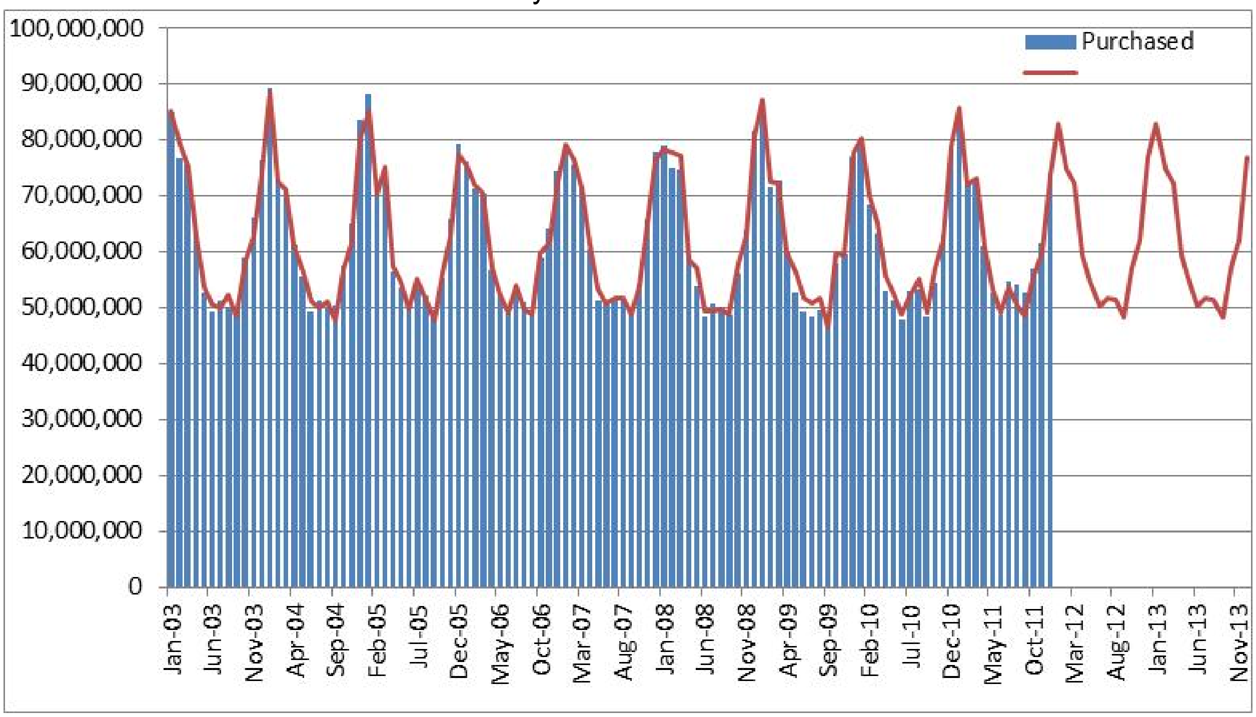
Answer: As shown in Exhibit 3, Tab 1, Schedule 4, Page 10 of 21, Table 3-19 the level of actual power purchases in 2012 has declined from 2005 by 200.7 GWh (i.e. 2,086.4 – 1,885.7). The net CDM results from 2012 program plus the persistence of 2006 to 2011 OPA CDM programs in 2012 is 55.9 GWh. 6.6 GWh of this amount is from 2012 programs shown in Exhibit 3, Tab 1, Schedule 4, Page 17 of 21, Table 3-29, 2012 programs under 2012. The remaining 49.3 GWh is from the persistence of 2006 to 2011 programs outlined in Exhibit 3, Tab 1, Schedule 4, Page 7 of 21, Table 3-17 the total 2012 values. For 2012, the CDM activity variable reflects 55.9 GWh from the impact of CDM programs initiated from the end of 2005 to 2012. Over the same period actual purchases have declined by 200.7 GWh and 200.7 divided by 55.9 is 3.6. This is very close to the absolute value of the coefficient for the CDM activity variable being (3.88). As a result, in KWHI's view this provides evidence to support the coefficient for the CDM activity variable which suggests it is addressing the constant pattern of decline in power purchases that is more than the impact of net CDM results. The decline could be attributed to such items not included in the CDM net results such 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 declining economic conditions in the KWHI service area that are not being addressed by other economic variables such as Ontario Real GDP, Employment and Unemployment stats.

d) Please provide KWHI's views of the reasonableness of multiplying the persistence of 2011 and 2012 CDM programs on the 2013 and 2014 forecast by the CDM coefficient.

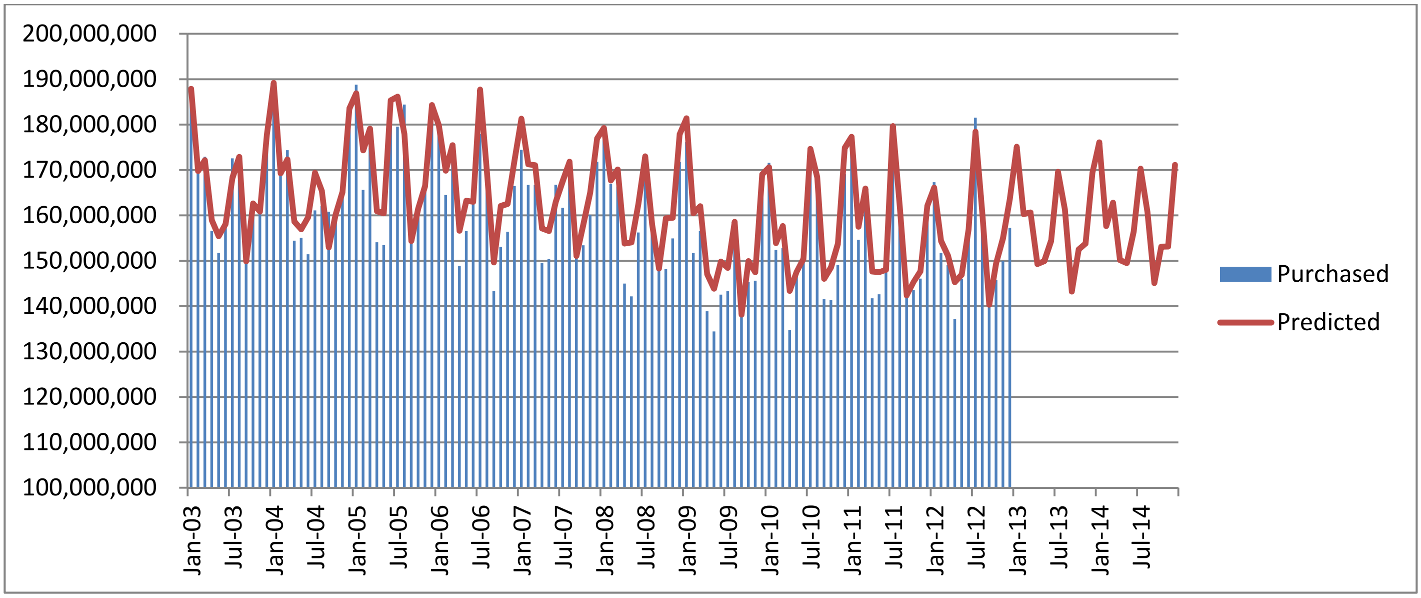
Answer: Multiplying the persistence of all programs from 2006 to 2012 into 2013 and 2014 by the CDM coefficient appears reasonable to KWHI since the historical relationship between the persistence of actual programs and the level of power purchases is expected to continue into 2013 and 2014.

3-Staff-16 Ref: Exhibit 3/Tab 1/Schedule 4/Table 3-18

a) As the regression model is based on monthly data, please file a version of the graph of actuals versus fitted based on the monthly results in a format similar to that shown below.



Answer: See chart below:

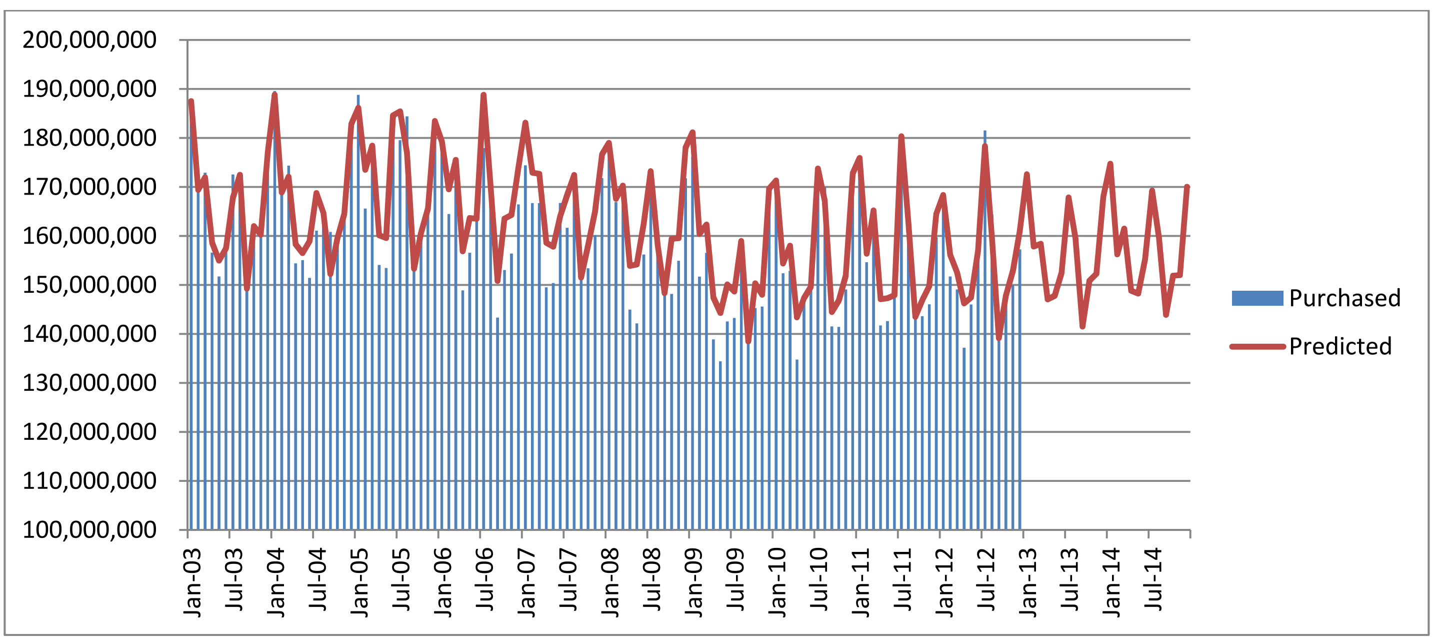


b) Please provide the Mean Absolute Percentage Error of the model based on the monthly residuals.

Answer: **1.9%**

c) Please provide a) and b) based on the model estimated in response to 3-Staff-16 c).*(s/b 3-Staff-15 b) as per Keith Ritchie)*

Answer: **See chart below:**



3-Staff-17 Exhibit 3/Tab 1/Schedule 4

a) Please provide a copy of the final 2012 OPA report for KWHI, if available.

Answer: Attached as Appendix C

b) Please provide a completed Appendix 2-I from the Appendices to the Filing Requirements for Transmission and Distribution Applications, issued July 17, 2013. This Appendix should also be provided in working Microsoft Excel format.

Answer: Included in Appendix A

End of Board Staff Exhibit Three Interrogatories

Energy Probe Exhibit Three Interrogatories

3-Energy Probe-17

Ref: Exhibit 3, Tab 1, Schedule 2

a) What is the Accounting Changes Under CGAAP shown in Table 3-1 for 2012 and 2013 related to?

Answer: See the explanation that was provided at Exhibit 3, Tab 1, Schedule 2, page 10 of 10 quoted below:

"Note that other revenue in 2012 was affected by the KWHI's entry to account 1576 – Accounting Changes under CGAAP. This entry was created to decrease KWHI's rate of return to coincide with the revenue requirement created under pre-2012 GAAP during KWHI's last rebasing in 2010 (EB-2009-0267) with the offset to other revenue. The reduction to other revenue was $2,265,213. An additional $3,676,200 was booked in the 2013 Bridge Year."

b) Please explain why and how KWHI's rate of return was decreased to coincide with the revenue requirement created under pre-2012 GAAP

Answer: Since KWHI last rebased under pre-2012 CGAAP, its forecasted financial statements and regulated rate of return were determined using the pre-2012 methodology. During the year 2012, KWHI changed the service lives of its fixed assets and its burdening methodology to coincide with those required under IFRS (although IFRS was not fully adopted). Since the methodologies followed by KWHI changed in 2012, its regulated financial results do not match what would be calculated if the same accounting procedures were followed as were used when KWHI's rates were last reset. The entries to 1576 endeavour to reach the same result

that would have been reached if the accounting methodologies had not been changed. The Board approved a deferral account through its initiative for the transition to IFRS and further clarified the accounting treatments in its July 2012 FAQ.

In other words, it is KWHI's understanding that entries to account 1576 have decreased KWHI's rate of return to coincide with the revenue requirement created under pre-2012 GAAP.

3-Energy Probe-18

Ref: Exhibit 3, Tab 1, Schedule 4

a) Please explain why the average loss factor used to adjust the purchases forecast is not for the same period (1997 through 2012) as is the data used to estimate the regression equation, but rather 2000 through 2012. If available, please calculate the loss factor for 1997 through 2012.

Answer: KWHI determined that in the absence of unbilled revenue for the period prior to 2000, the calculations were unreliable.

b) Did KWHI attempt to remove the actual consumption for the Maple Leaf/J.M. Schneider account over the period 1997 through 2012 and run the regression excluding this account which is expected to be closed in 2014? If not, why not?

Answer: No, KWHI felt that it was more appropriate to use actual data for future purchases rather than manipulate the past.

3-Energy Probe-19

Ref: Exhibit 3, Tab 1, Schedule 4

Based on the spreadsheet provided, it does not appear that KWHI has forecast any changes in the level of employment or unemployment from that recorded in December 2012.

a) Please confirm that this is the case and explain why no forecast change to either variable was made.

Answer: Confirmed. After reviewing the historical monthly data for employment and unemployment, KWHI was unable to develop a method that would produce a just and reasonable forecast for employment and unemployment values. As a result, the forecast of employment and unemployment values were held constant at the last month of actual data (i.e. Dec 2012).

b) Please update the employment and unemployment variables to reflect the most recent data available. Based on those figures, please provide the forecast for 2014. Please also provide the live Excel spreadsheet that reflects this update.

Answer: The 2014 employment variable used was 718 and the unemployment variable used was 48. See live Excel Spreadsheet entitled "Load Forecasting Model 3-EP-19".

3-Energy Probe-20

Ref: Exhibit 3, Tab 1, Schedule 4

a) Please confirm that the GS>50 kW/kWh ratio shown in Table 3-33 has remained relatively flat between 2002 and 2012.

Answer: Confirmed.

b) Please calculate the kW forecast for the 2014 year based on using the average rate for 2002 through 2012 for the GS>50 class.

Answer: Using the average rate for 2002 through 2012, GS>50kW demand is now calculated to be 2,237,627 kW, an increase of 54,379 kW from the original forecast, as filed with the Board, of 2,183,248 kW. Year 2000 and 2001 had much lower demand, therefore reducing the average.

c) What is the impact on the revenue deficiency/sufficiency in 2014 of this change?

Answer: Distribution revenue at existing rates would be increased by $220,740 from $38,207,936 to $38,428,676. The revenue requirement would therefore decrease by $220,740. See table below:

Forecast Class Billing Determinants for 2014 Test Year Based on Existing Class Revenue Proportions
Revenue At Existing Rates

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	651,926,620		990,924		9,671,418	11,278,331	20,949,749		20,949,749	54.52%
GS <50 kW	241,614,912		93,960		2,415,712	2,996,025	5,411,737		5,411,737	14.08%
GS >50 kW	844,886,400	2,237,627	11,340		2,695,745	9,083,199	11,778,943	631,891	11,147,053	29.01%
Large Use	31,798,990	63,002	12		174,019	87,068	261,088	37,801	223,286	0.58%
Street Lighting	16,128,465	45,145		295,356	236,285	241,013	477,297		477,297	1.24%
Unmetered Scattered Load	3,417,188			10,680	90,994	56,725	147,719		147,719	0.38%
Embedded Distributor	20,328,822	44,674	0		0	71,835	71,835		71,835	0.19%
	1,810,101,397	2,390,448	1,096,236	306,036	15,284,172	23,814,196	39,098,368	669,692	38,428,676	100%

3-Energy Probe-21

Ref: Exhibit 3, Tab 1, Schedule 4

Please provide a table that shows that derivation of the energy purchases and billed kWh forecast for 2014, starting with the 1,906.0 GWh shown in Table 3-19 for purchases and the 1,842.5 GWh Billed forecast noted on page 11, the adjustments for CDM, the large use customer and the embedded distributor to arrive at the energy purchase figure 1,871.8 GWh and billed energy of 1,789.8 GWh shown in Table 3-35.

Answer:

Derivation of 1,789.8 GWh

1,906,032,582	Modelled Purchases
1.0345	Average Loss Factor
1,842,467,455	Modelled Purchases divided by Average Loss Factor
34,217,838	LU Adjustment so that forecast is only for the remaining LU
1,808,249,617	Loss Adjusted Modelled Purchases further adjusted to only include remaining large user
18,474,798	CDM Adjustment
1,789,774,819	Above total further adjusted to include reductions expected from CDM programs

Derivation of 1,871.8 GWh

1,906,032,582	Modelled Purchases
34,217,838	LU Adjustment to be only the remaining LU
1,871,814,744	Non-loss adjusted Modelled Purchases adjusted to one Large User

The embedded distributor is not part of the calculations for power purchased.

Note: Table 3-35 does NOT include adjustments for system losses and CDM. The only adjustment reflected is the loss of one Large Use customer.

Based on the submission of August 9th, the predicted GWh for 2013 should be 1,789.8, this is the figure used to develop the proposed rates.

3-Energy Probe-22

Ref: Exhibit 3, Tab 1, Schedule 5

a) Please explain why KWHI believes that 2002 and 2012 figures should be included in the averages used to forecast the embedded distributor figures, as shown in Table 3-36.

Answer: KWHI has been the host distributor to Waterloo North Hydro Inc. only since the year 2002 and the data included in Table 3-36 is the only data that it has available. A longer data series would be desirable but is not available. Since Waterloo North Hydro Inc. is not expecting any significant changes, KWHI used the average for that time period.

b) Please provide a revised Table 3-36 that only uses 2007 through 2011 data in the calculation of the averages.

Answer:

kW Demand & kWh Consumption

Year	2002 - 2012		2007 - 2011	
	kW	kWh	kW	kWh
2002	29,356.80	15,328,897	-	-
2003	43,881.60	20,418,901	-	-
2004	40,502.40	19,486,436	-	-
2005	43,934.37	16,865,800	-	-
2006	45,564.29	21,112,323	-	-
2007	49,751.52	22,263,925	49,752	22,263,925
2008	48,353.00	22,427,621	48,353	22,427,621
2009	49,918.17	22,622,442	49,918	22,622,442
2010	53,143.52	24,190,281	53,144	24,190,281
2011	49,138.90	21,309,995	49,139	21,309,995
2012	37,866.88	17,590,424		
Total	*491,411.44*	*223,617,046*	*250,305.10*	*112,814,265*
Average	44,673.77	20,328,822	50,061.02	22,562,853

c) What is the impact on the revenue deficiency/sufficiency if the average calculated in part (b) above was used for the embedded distributor in 2014?

Answer: The revenue at current rates would increase to $38,213,331 from $38,207,936 as shown below:

Forecast Class Billing Determinants for 2014 Test Year Based on Existing Class Revenue Proportions
Revenue At Existing Rates

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	651,926,620		990,924		9,671,418	11,278,331	20,949,749		20,949,749	54.82%
GS <50 kW	241,614,912		93,960		2,415,712	2,996,025	5,411,737		5,411,737	14.16%
GS >50 kW	844,886,400	2,183,248	11,340		2,695,745	8,862,459	11,558,203	631,891	10,926,313	28.59%
Large Use	31,798,990	63,002	12		174,019	87,068	261,088	37,801	223,286	0.58%
Street Lighting	16,128,465	45,145		295,356	236,285	241,013	477,297		477,297	1.25%
Unmetered Scattered Load	3,417,188			10,680	90,994	56,725	147,719		147,719	0.39%
Embedded Distributor	21,734,115	48,029	0		0	77,230	77,230		77,230	0.20%
	1,811,506,689	2,339,424	1,096,236	306,036	15,284,172	23,598,850	38,883,023	669,692	38,213,331	100%

As a result of the adjustments above, the revenue sufficiency would decrease by $5,395 from $798,663 to $793,268 as shown below:

Below see the table below filed August 9, 2013 showing the $793,268 revenue sufficiency before the adjustments:

Revenue Sufficiency/Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test Required Revenue
Revenue:			
Revenue Deficiency			**(793,268)**
Distribution Revenue	38,163,923	38,207,936	38,207,936
Other Operating Revenue (Net)	1,840,800	2,039,200	2,039,200
Accounting Changes Under CGAAP - Account 1576	(3,676,200)		
Total Revenue	**36,328,523**	**40,247,136**	**39,453,868**
Costs and Expenses:			
Administrative & General, Billing & Collecting	6,805,075	7,261,800	7,261,800
Operation & Maintenance	10,626,000	11,261,400	11,261,400
Depreciation & Amortization	7,169,353	7,562,853	7,562,853
Property Taxes	376,000	394,800	394,800
Capital Taxes			
Deemed Interest	6,801,351	5,019,405	5,019,405
Total Costs and Expenses	**31,777,778**	**31,500,258**	**31,500,258**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**31,777,778**	**31,500,258**	**31,500,258**
Utility Income Before Income Taxes	**4,550,744**	**8,746,879**	**7,953,610**
Income Taxes:			
Corporate Income Taxes	578,252	643,543	433,327
Total Income Taxes	**578,252**	**643,543**	**433,327**
Utility Net Income	**3,972,493**	**8,103,335**	**7,520,283**

The updated table is presented below:

Revenue Sufficiency/Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test Required Revenue
Revenue:			
Revenue Deficiency			(798,663)
Distribution Revenue	38,163,923	38,213,331	38,213,331
Other Operating Revenue (Net)	1,840,800	2,039,200	2,039,200
Accounting Changes Under CGAAP - Account 1576	(3,676,200)		
Total Revenue	**36,328,523**	**40,252,531**	**39,453,868**
Costs and Expenses:			
Administrative & General, Billing & Collecting	6,805,075	7,261,800	7,261,800
Operation & Maintenance	10,626,000	11,261,400	11,261,400
Depreciation & Amortization	7,169,353	7,562,853	7,562,853
Property Taxes	376,000	394,800	394,800
Capital Taxes			
Deemed Interest	6,801,351	5,019,405	5,019,405
Total Costs and Expenses	**31,777,778**	**31,500,258**	**31,500,258**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**31,777,778**	**31,500,258**	**31,500,258**
Utility Income Before Income Taxes	**4,550,744**	**8,752,273**	**7,953,610**
Income Taxes:			
Corporate Income Taxes		644,973	433,327
Total Income Taxes		**644,973**	**433,327**
Utility Net Income	**4,550,744**	**8,107,300**	**7,520,283**

d) Please provide the most recent year-to-date consumption (kW and kWh) for 2013 and the corresponding figures for the same period in each of 2007 through 2011.

Answer: See table below in kW by month:

Embedded Distributor
Monthly Billings January 2007 - August 2013
kW

	2007	2008	2009	2010	2011	2012	2013
Month	kW	kW	kW	kW	kW	kW	kW
January	4277	4572	4981	4645	5139	3530	3299
February	4844	4448	4770	4685	4949	3379	2793
March	4382	4050	4797	4209	4325	3228	2587
April	3579	3616	3880	3417	3813	2628	2369
May	3205	3118	3520	3919	3929	2938	2325
June	4222	3984	4775	4135	4172	3285	2669
July	4471	4002	4072	4833	4639	3383	3036
August	4510	3820	4251	4654	3958	3038	2639
September	4060	3720	2992	4605	3845	2947	
October	3497	3960	3274	4217	3218	2924	
November	4327	4156	3863	4684	3705	3139	
December	4377	4906	4744	5141	3446	3449	

Totals

January - December	49,752	48,353	49,918	53,144	49,139	37,867	Not complete
January - August	33,490	31,611	35,045	34,497	34,925	25,408	21,716

See table below in kWh by month:

Embedded Distributor
Monthly Billings January 2007 - August 2013
kWh

	2007	2008	2009	2010	2011	2012	2013
Month	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**
January	2,142,622	2,247,302	2,505,570	2,367,128	2,505,715	1,766,125	1,667,581
February	2,087,780	2,093,295	2,095,180	2,115,800	2,162,878	1,578,509	1,333,719
March	1,964,479	2,050,705	2,131,282	1,991,069	2,190,711	1,488,470	1,344,716
April	1,703,734	1,613,515	1,795,732	1,639,209	1,863,694	1,308,730	957,662
May	1,495,802	1,547,125	1,702,956	1,766,232	1,686,153	1,282,260	1,087,301
June	1,607,858	1,627,795	1,924,603	1,819,852	1,596,159	1,384,354	1,130,486
July	1,831,162	1,794,591	1,940,117	2,086,393	1,978,849	1,549,527	1,310,226
August	1,897,794	1,698,141	1,831,077	2,098,876	1,789,482	1,403,942	1,226,811
September	1,629,345	1,632,637	1,341,244	1,779,188	1,599,175	1,252,243	
October	1,750,166	1,790,868	1,601,461	1,937,691	1,597,086	1,399,464	
November	1,932,921	1,974,661	1,661,498	2,072,456	1,665,732	1,514,313	
December	2,220,260	2,356,985	2,091,722	2,516,386	674,361	1,662,488	
Totals							
January - December	22,263,925	22,427,621	22,622,442	24,190,281	21,309,995	17,590,424	Not complete
January - August	14,731,232	14,672,470	15,926,517	15,884,560	15,773,640	11,761,917	10,058,503

3-Energy Probe-23

Ref: Exhibit 3, Tab 1, Schedule 5

With respect to the closure of the Maple Leaf Foods plant, please provide the following:

a) The reduction in the kWh forecast for 2014 and how this figure was arrived at;

Answer: The forecast load for the large use rate class was estimated by calculating the average demand for the remaining large use customer. This customer was reclassified to the large use category in June 2011. The average load is 31,798,990 kWh as seen below:

Table 3-39

Period	kWh	kW
11-Jun	2,656,702.29	5,422.0320
11-Jul	2,453,203.43	5,311.1520
11-Aug	2,774,492.08	5,344.4160
11-Sep	2,610,932.99	5,078.3034
11-Oct	2,766,213.64	4,645.8720
11-Nov	2,682,213.18	5,488.5600
11-Dec	2,331,092.86	5,100.4800
12-Jan	2,732,241.34	5,189.1840
12-Feb	2,663,289.01	5,388.7674
12-Mar	2,804,734.72	5,333.3280
12-Apr	2,723,836.22	5,344.1600
12-May	2,908,298.32	5,277.8880
12-Jun	2,687,220.78	5,333.3280
12-Jul	2,458,095.62	5,288.9760
12-Aug	2,810,634.63	5,155.9200
12-Sep	2,598,209.91	5,288.9760
12-Oct	2,800,613.80	5,344.4160
12-Nov	2,611,614.18	5,189.1834
12-Dec	2,274,762.28	5,155.9200
Average	**2,649,915.86**	**5,246.3612**
Annual	**31,798,990.29**	

The default for the load forecast model uses average consumption per customer which in the case is 31,419,041 kWh. KWHI adjusted this value up to the 31,798,990 kWh to estimate the required reduction to the large use category.

The reduction is 31,039,092 kWh (from 62,838,082 kWh to 31,798,990 kWh).

b) The most current expectation of when the plant and distribution center will be closed;

Answer: The distribution centre officially closed on September 1, 2013. The full plant will transfer production to a new location outside KWHI's territory throughout 2014 with an expectation that the Kitchener facility will close before the end of 2014.

c) The expected distribution revenue that KWHI will receive in 2014 before the plant and distribution center close;

Answer: Although this is a largely unknown amount, based on the previous three years history it has been estimated that this large user's distribution revenue will be $304K. KWHI contacted the customer but the customer is unwilling to provide an estimate of the monthly load after closure.

d) The expected use, if known, of the property that houses the plant and distribution center, including any indication of any plans that the City of Kitchener may have for the property;

Answer: KWHI has no knowledge of the expected use of the property at this time. The last time KWHI experienced the loss of an industrial customer of this magnitude, the facility sat idle for 30 months consuming a fraction of its previous load. It was then demolished and has yet to be developed 23 months later.

e) Confirmation that KWHI has not included any distribution revenue in the 2014 forecast from this customer. If this cannot be confirmed, please indicate the total distribution revenue included in the 2014 forecast.

Answer: Confirmed

3-Energy Probe-24

Ref: Exhibit 3, Tab 1, Schedule 5

Please update Table 3-39 to reflect actual data for as many months are currently available in 2013.

Answer: See Below

Table 3-39

	kWh	kW
11-Jun	2,656,702.29	5,422.0320
11-Jul	2,453,203.43	5,311.1520
11-Aug	2,774,492.08	5,344.4160
11-Sep	2,610,932.99	5,078.3034
11-Oct	2,766,213.64	4,645.8720
11-Nov	2,682,213.18	5,488.5600
11-Dec	2,331,092.86	5,100.4800
12-Jan	2,732,241.34	5,189.1800
12-Feb	2,663,289.01	5,388.7674
12-Mar	2,804,734.72	5,333.3280
12-Apr	2,723,836.22	5,344.1600
12-May	2,908,298.32	5,277.8880
12-Jun	2,687,220.78	5,333.3280
12-Jul	2,458,095.62	5,288.9760
12-Aug	2,810,634.63	5,155.9200
12-Sep	2,598,209.91	5,288.9760
12-Oct	2,800,613.80	5,344.4160
12-Nov	2,611,614.18	5,189.1834
12-Dec	2,274,762.28	5,155.9200
13-Jan	2,700,323.86	5,178.0960
13-Feb	2,454,878.26	5,322.2400
13-Mar	2,646,264.86	5,288.9760
13-Apr	2,636,373.51	5,144.8320
13-May	2,708,624.82	5,178.0960
13-Jun	2,543,869.42	5,311.1520
13-Jul	2,299,119.08	5,388.5360
13-Aug	2,924,722.90	5,233.5360
AVERAGE	**2,639,354.74**	

3-Energy Probe-25

Ref: Exhibit 3, Tab 1, Schedule 9

a) Please provide the most current year-to-date actual revenues available for 2013 in the same level of detail as shown in Table 3-48. Please also provide the figures for the corresponding period in 2012.

Answer:

Summary of Other Revenue
2012 - 2013

January - August

Revenue Type	August 2012	August 2013
Other Regulatory Debits		
Accounting Changes Under CGAAP	$0	$0
Other Revenue		
SSS Administration Charges	164,228	168,915
Retailer Services Revenue	44,123	34,912
Late Payment Charge	162,939	161,595
Specific Service Charges	168,163	173,235
Other Distribution Revenue	390,633	540,369
Other Income and Deductions **	601,752	396,237
CDM (OPA) Revenues (net)	115,820	(85,221)
Gross Other Revenues	1,647,657	1,390,041
Fixed Asset Gains/Losses @ 50%	(34,134)	(5,840)
Remove Variance Account Interest	(72,604)	(102,986)
Adjusted Other Revenue	1,540,920	1,281,215

** Note Other Income & Deductions includes $84,800 for Contributed Capital Deferred Revenue subsequently reversed as MIFRS was not fully adopted in 2012.

b) Please reconcile the 2014 forecast of $321,800 shown in Table 3-51 for change of occupancy charges with the $20 proposed rate and 16,680 occurrences in 2014.

Answer:

The 2014 budget of $321,800 was calculated as follows

Proposed Fee less current fee ($20 - $10)	**10**
Average occurrences per year	**x 16, 580**
	165,800
add estimate for growth over 2013	**1,000**
subtotal additional revenue	**166,800**
Add 2013 Budget	**155,000**
Total 2014 Budget	**321,800**

Note that the budget for 2013 includes the existing $10 fee.

c) Please explain why KWHI believes that the account setup/change of occupancy charge should be rounded to the nearest $5.

Answer: KWHI used the generic worksheet for "Specific Service Charges" developed during the 2006 EDR. The worksheet details that the service charge valued be rounded to the nearest $5. It is not specific to round up or down. KWHI's final calculation landed at $21.95 and KWHI chose to round down to $20.

d) Please reconcile the 2014 forecast of $63,300 shown in Table 3-51 for reconnection charges revenue with the proposed rates and number of occurrences noted on pages 5 through 7.

Answer:

The 2014 budget of $63,300 was calculated as follows:
The Reconnection charges revenue is the sum of two activities:

1) **Reconnection charges during regular business hours**
2) **Reconnection charges after regular business hours.**

Reconnection Activity	Historical Average of occurrences	Estimated occurrences	Rate	Revenue
Regular Business hours	857	860	$65	55,900
After Regular Business hours	153	40	$185	7,400
				63,300

Note - the estimated occurrences for After Regular Business Hours was reduced to 40 from the historical average of 153, to reflect the anticipated reduction in occurrences, when customers can choose to delay their service to regular business hours to take advantage of the lower rate applicable to regular business hours.

e) Please explain the 50% claw back on the fixed asset gains shown in 2014 in Table 3-48. What are the gains related to?

Answer: KWHI estimates that its gains on fixed asset disposals will be $30K, 50% of which would flow back to customers and the other 50% kept by the shareholders of KWHI. The 50% removal on gains on fixed asset disposals was also applied in KWHI's 2010 cost of service application (EB-2009-0367). KWHI (as a general rules) does not dispose of fixed assets until they are fully depreciated, at which time they are scrapped or removed from the pool (in the case of pooled assets). The $30K forecast is for utility transportation equipment which KWHI typically sells at auction (for smaller trucks) or trades in (for larger trucks) when purchasing new vehicles.

3-Energy Probe-26

Ref: Exhibit 3, Tab 1, Schedule 10 &
Exhibit 3, Tab 1, Schedule 4

a) What assumptions has KWHI made with respect to the increase in the number of customers forecast in calculating the SSS and retailer service revenues? In particular, please show the link between the customer forecast in Exhibit 3, Tab 1, Schedule 4 with the increases in revenue shown for 2013 and 2014 in the figure shown in the top table on page 1 of Exhibit 3, Tab 1, Schedule 10.

Answer: There is no direct link between the customer forecast developed for this rate application and the SSS administration charges and retailer services revenue budgets.

SSS Administration Charges

There is no direct link between the number of customers forecast and the budget amounts projected for SSS Admin Fee Revenue.

The 2013 Bridge Budget for SSS administration revenues was calculated at a 1% increase over projected 2012 revenues of $247,000 and rounded to $249,300. The 2014 Test Budget was calculated as a 1% increase on the 2013 Bridge budget of $249,300 and rounded to $251,800. The budgets are based on projected revenue growth rates and not on actual number of customers each month as the SSS administration charges apply incrementally through the partial service year when new customers sign on part way through the year and the pattern is unpredictable.

Retailer Services Revenue

KWHI has found that retailer services revenue has been difficult to predict. Retailer services revenue has not been budgeted by KWHI based on the estimated number of customers enrolled with a retailer but rather by estimated dollar amounts. Actuals versus forecasts for 2013 and 2014 are presented below:

	DESCRIPTION	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 ACTUAL	2013 BRIDGE	2014 TEST
4082	Retailer Services	95,879	85,469	75,952	61,296	66,800	68,000
4084	STR	2,335	3,606	1,969	1,959	2,200	2,300
		98,214	**89,075**	**77,921**	**63,255**	**69,000**	**70,300**
	$$ Change from Prior Year		(10,410)	(9,517)	(14,656)	5,504	1,200
	%% Change from Prior Year		-10.86%	-11.13%	-19.30%	8.98%	1.80%

Historically, there has been very little consistency with retailer customer counts and retailer activity which makes it difficult for KWHI to tie estimated retailer numbers with the load

forecast. It should also be noted that retailer services revenues and costs are directly linked to two variance accounts – 1518 RCVA Retailer Services and 1548 – RCVA STR. The amounts shown above are not what is seen in KWHI's audited financial statements. The revenues for retailer services are adjusted to record the lower of revenues and costs for both types of retailer-related services. The difference is recorded in the corresponding retailer service variance account (1518 or 1548). Since both costs and revenues related to servicing retailer are adjusted to equal one another, the amounts recorded to the audited financial statements will generally differ from actual.

b) With respect to Account 4210, please provide the amount of rent received for its basement for each of the years shown.

Answer:

Basement Rent Revenue

2009	77,309
2010	86,786
2011	89,255
2012	52,940
2013	-
	306,290

c) Where did KWHI have its training facilities while the basement was being rented out to a third party?

Answer: KWHI had its training room on the second floor in the Customer Service area. This area has since been taken over by the CDM group.

d) Does KWHI have any obsolete inventory in 2013 or forecast for 2014, similar to that written off in 2012? Please explain fully.

Answer: No, KWHI has not forecasted any write off of obsolete inventory in 2013 and 2014. A full analysis of inventory had not been completed for many years and a full (overdue) analysis was complete in 2012 to bring inventory items completely up to date.

3-Energy Probe-27

Ref: Exhibit 3, Tab 1, Appendix 3-A

a) Please explain why KWHI has used a non-RPP price of $0.08717 to calculate the cost of power.

Answer: This is the weighted average price estimate at that time and the global adjustment estimate as per the April, 2013 RPP Price Report.

b) Please confirm that this figure is sum of $0.02105 for the load-weighted price for RPP customers and $0.06612 for the global adjustment in the April, 2013 Regulated Price Plan Price Report. If this cannot be confirmed, please indicate how the $0.081717 has been arrived at.

Answer: **Confirmed**

c) Please recalculate the cost of power for 2014 using a non-RPP price of $0.08545, being the sum of the global adjustment and the forecast wholesale electricity price.

Answer:

Electricity - Commodity Non-RPP **Class per Load Forecast**	**2014 Forecasted**	**2014 Loss Factor**	**2014**		
Residential	39,806,800	1.0351	41,205,692	$0.08545	$3,521,026
General Service< 50 kW	33,662,402	1.0351	34,845,368	$0.08545	$2,977,537
General Service> 50 kW	705,197,537	1.0351	729,979,625	$0.08545	$62,376,759
Large User	31,798,990	1.0053	31,967,525	$0.08545	$2,731,625
Streetlights	16,128,465	1.0351	16,695,252	$0.08545	$1,426,609
Unmetered Loads	3,417,188	1.0351	3,537,275	$0.08545	$302,260
Embedded Distributor	0	1.0351	0	$0.08545	$0
TOTAL	**830,011,381**		**858,230,737**		**$73,335,817**

3-Energy Probe-28

Ref: Exhibit 3, Tab 1, Appendix 3-C

Please provide the most recent year-to-date figures available for 2013 in the same level of detail as found in Appendix 2-F (excluding Account 4350). Please also provide the figures for the corresponding period in 2012 in the same level of detail.

Answer: **Included in Appendix A**

End of Energy Probe Exhibit Three Interrogatories

No School Energy Coalition Exhibit Three Interrogatories

VECC Exhibit Three Interrogatories

3.0-VECC – 12

Reference: Exhibit 3, Tab 1, Schedule 4, page 5

a) For the one large user that is closing down operations, is the "service" being disconnected/discontinued or will a nominal load still continue to exist at the delivery point? If the latter, what is the expected monthly load after closure?

Answer: The distribution centre was closed on September 1st, 2013 with little impact on electricity load. The full plant will transfer production to a new plant outside KWHI's territory throughout 2014 with an expectation that the Kitchener facility will close by the end of 2014.

KWHI has no knowledge of the expected use of the property at this time. KWHI contacted the customer but the customer is unwilling to provide an estimate of the monthly load after closure. The last time KWHI experienced the loss of an industrial customer of this magnitude, the facility sat idle for 30 months consuming a fraction of its previous load. It was then demolished, and has yet to be redeveloped 23 months later.

3.0 – VECC – 13

Reference: Exhibit 3, Tab 1, Schedule 4, pages 5-8
Excel Load Forecast Model, Purchased Power Model Tab
2013 Ontario Budget
(http://www.fin.gov.on.ca/en/budget/ontariobudgets/2013/)
3-Staff-17 a)

a) Have sales to Kitchener's embedded distributor always been excluded from Kitchener's power purchase data? If not, for what years was it included and how was the historic purchased power data adjusted to account for this?

Answer: Yes, it has always been excluded from KWHI's power purchase data. KWHI only became the host distributor to Waterloo North Hydro Inc. (WNHI) upon market opening in 2002. Previously, WNHI was embedded to Hydro One Networks. Since becoming the host distributor, the embedded distributor has always been excluded from KWHI's power purchase data.

b) Please re-do the regression equation on page 6 without the CDM variable and provide the resulting equation, regression statistics and predicted 2014 purchases.

Answer: **KWHI's Monthly Predicted kWh Purchases**

= Heating Degree Days * 41,394
+ Cooling Degree Days * 302,561
+ Ontario Real GDP Monthly * 372,055
+ Number of Days in the Month * 3,795,247
+ Spring Fall Flag * (4,975,122)
+ Number of Peak Hours * 74,610
+ Employment Kitchener-Waterloo, Barrie * (19,569)
+ Unemployment Kitchener-Waterloo, Barrie * (529,969)
+ Intercept of (8,736,504)

Regression Statistics	
Multiple R	0.924008209
R Square	0.85379117
Adjusted R Square	0.847399527
Standard Error	4837389.158
Observations	192

	t Stat
Intercept	-0.60331051
Heating Degree Days	19.36249605
Cooling Degree Days	14.76172489
Ontario Real GDP Monthly %	3.896908838
Number of Days in Month	8.100193292
Spring Fall Flag	-5.345535629
Number of Peak Hours	3.353255778
Employment Kitchener-Waterloo-Barrie (000's)	-0.859406685
Unemployment Kitchener-Waterloo-Barrie (000's)	-12.61898065

2014 Predicted Purchases before Manual Adjustments - 1,860,250,508

Note that the employment variable now has a non-intuitive coefficient and the t-stat suggests it is not statistically significant.

c) Why were both employment and unemployment included as variables? Please re-do the regression equation excluding the unemployment variable and provide the resulting equation and regression statistics.

Answer: **Both the employment and unemployment figures were used as it is KWHI's view that these two variables provide a good representation of the local economic conditions in the Kitchener Wilmot area. Growth in employment statistics indicate growing economic conditions and growth in unemployment statistics suggest declining economic conditions. Since both variables proved to be statistically significant and the coefficients on the variables were intuitive, it was thought best to include both variables in the prediction formula to pick up as many economic conditions as possible.**

The regression equation is redone below as requested:

KWHI's Monthly Predicted kWh Purchases

= Heating Degree Days * 42,049
+ Cooling Degree Days * 296,874
+ Ontario Real GDP Monthly * 94,998
+ Number of Days in the Month * 3,535,592
+ Spring Fall Flag * (4,438,565)
+ CDM Activity * (4.72)
+ Number of Peak Hours * 77,848
+ Employment Kitchener-Waterloo, Barrie * 95,353
+ Intercept of (53,552,408)

Regression Statistics	
Multiple R	0.947334743
R Square	0.897443115
Adjusted R Square	0.892959754
Standard Error	4051414.114
Observations	192

	t Stat
Intercept	-4.29743309
Heating Degree Days	23.51335521
Cooling Degree Days	17.28264669
Ontario Real GDP Monthly %	1.19947205
Number of Days in Month	9.015637395
Spring Fall Flag	-5.700118807
CDM Activity	-17.4616126
Number of Peak Hours	4.178800413
Employment Kitchener-Waterloo-Barrie (000's)	4.71649592

Note that the GDP value has a t-stat less than 2 which suggests it is not statistically significant.

d) The Excel Load Forecast model filed with the application shows that employment and unemployment levels are forecast to be constant through 2013 and 2014 at December 2012 levels. What is the basis for this forecast?

Answer: After reviewing the historical monthly data for employment and unemployment KWHI was unable to develop a method that would produce a just and reasonable forecast for employment and unemployment values. As a result, the forecast of employment and unemployment values were held constant at the last month of actual data (i.e. Dec 2012)

e) The 2013 Ontario Budget calls for employment growth increases in 2013 and 2014 of 1.2% and 1.4% respectively and a decrease in unemployment rates. Please what is the forecast power purchases for 2014 using these growth rates in conjunction with:

i. The regression model estimated by Kitchener in its Application

Answer: Weather Corrected Forecast before 2013 and 2014 CDM Adjustments is 1,821,300,211

ii. The regression model developed in response to part (c)?

Answer: Weather Corrected Forecast before 2013 and 2014 CDM Adjustments is 1,797,332,304

f) With respect to Table 3-17, please provide a schedule that sets out the impact as assumed in the regression model from the 2008-2012 CDM programs, showing the impact of each year's programs in each year of the historical period.

Answer: See table below:

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Third Tranche	292,583	4,688,792	11,539,979	13,901,639	14,769,006	14,630,348	14,630,348	14,282,990	9,108,721	9,108,721
2006 Programs		6,036,035	6,036,035	6,036,035	6,036,035	1,048,326	1,048,326	958,933	958,933	901,065
2007 Programs			3,887,775	3,111,482	3,016,918	3,016,918	3,016,608	2,920,674	2,920,674	2,920,674
2008 Programs				4,009,754	3,663,596	3,663,596	3,663,596	3,373,055	3,372,487	3,070,530
2009 Programs					9,169,960	7,890,852	7,890,852	7,887,707	7,794,413	7,491,580
2010 Programs						9,393,558	7,125,232	7,116,405	7,115,045	7,023,483
2011 Programs							12,882,629	12,777,283	12,766,733	12,588,174
2012 Programs								6,561,443	6,561,443	6,561,443
Total	292,583	10,724,827	21,463,789	27,058,909	36,655,515	39,643,598	50,257,589	55,878,490	50,598,449	49,665,669
	292,583	10,724,827	21,463,789	27,058,909	36,655,515	39,643,598	50,257,589	55,878,490	50,598,449	49,665,669

g) Please provide a schedule that sets out the impact as assumed in the forecast for 2013 and 2014 of the CDM programs implemented in 2008 through 2012. Please show the impact of each of these year's programs on the 2013 and 2014 separately.

Answer: See table from f) above

h) If the final 2012 OPA Report (as requested in 3-Staff-17 a)) is not available, please provide any preliminary reports the OPA has produced on CDM savings from 2012 programs.

Answer: See attached Appendix C

3.0 – VECC –14

Reference: Exhibit 3, Tab 1, Schedule 4, pages 11-14
Exhibit 3, Tab 1, Schedule 5, pages 4-5
Excel Load Forecast Model, Retail Class Energy Model Tab

a) Contrary to the text in the Application (Schedule 5, page 5, lines 10-11) there is no adjustment shown to the Large User rate class forecast at the referenced cell. Please provide the derivation of the 2014 Large User class load prior to the loss of Maple Leaf Foods.

Answer: The cell reference should be O80. The amount is derived from the actual amounts of KWHI's forecasted remaining Large User, rather than calculated in the same manner as the other classes.

b) The Retail Class Energy Model Tab does not show the actual calculation (i.e. formulae used) to determine the Non-normalized weather billed energy by class as set out in Table 3-26, please provide a version that does so.

Answer: Original Load Forecast Excel Spreadsheet with formulas is attached.

c) Please provide Kitchener's actual customer count by rate class (comparable to Table 3-20) for the end of June 2013.

Answer: See table below. Note the customer numbers are from January to August for 2013.

Table 3-20: Historical Customer/Connection Data for Energy

Year	Residential	GS<50	GS>50	Large User	Street Lighting	USL	Total
Number of Customers/Connections							
2000	63,692	6,548	1,033	3	1,342	750	73,368
2001	64,284	6,568	1,035	4	1,370	750	74,011
2002	65,683	6,569	1,068	4	1,394	765	75,483
2003	67,527	6,703	1,035	4	1,405	765	77,439
2004	69,405	6,816	1,058	4	1,497	822	79,602
2005	71,490	6,916	1,077	4	1,517	807	81,811
2006	72,866	7,049	1,021	4	1,533	807	83,280
2007	74,392	7,198	1,005	4	1,523	818	84,940
2008	75,154	7,265	1,014	4	1,522	820	85,779
2009	76,255	7,370	1,005	3	1,551	817	87,001
2010	77,506	7,448	989	1	1,574	811	88,329
2011	78,761	7,538	975	2	1,568	841	89,685
2012	79,997	7,645	952	2	1,573	869	91,039
2013	**80,985**	**7,693**	**947**	**3**	**1,575**	**817**	**92,020**

3.0 – VECC – 15

Reference: Exhibit 3, Tab 1, Schedule 4, pages 15-18
Board Decision and Order re: Centre Wellington Hydro's 2013 Rates (EB-2012-0113), pages 6-7

a) On page 15, the text at lines 6-8 suggests that the -3 GWh difference for 2014 is prior to CDM adjustments, whereas the text at lines 24-26 suggests it is after. Please reconcile. Also, is the value -3 GWh or -0.3 GWh?

Answer: The value is -3 GWh. The text at lines 24-26 is incorrect it should have read before CDM adjustments.

b) In its Decision regarding Wellington Hydro's 2013 rates the Board directed that the impact in the first year of a CDM program be adjusted using the "half-year rule". Please recalculate the manual adjustment for 2014 (per Table 3-29) so as to be consistent with on the Board's direction in the Centre Wellington Decision.

Answer: The manual adjustment for 2014 (per Table 3-29) calculated in a manner consistent with the Board's direction in the Centre Wellington Decision is 13,856,098.

c) Please indicate how the 61,748 kW value for the GS>50 LRAM (Table 3-30) was calculated.

Answer: The value is calculated by taking the 2014 expected savings for LRAM Variance accounts from Table 3-30 for GS>50kW (24,232,313) and multiplying it by the average kW/kWh ratio of 0.2548%. See data below:

kW/kWh	General Service > 50 kW
2000	0.2022%
2001	0.2376%
2002	0.2604%
2003	0.2602%
2004	0.2579%
2005	0.2551%
2006	0.2681%
2007	0.2638%
2008	0.2658%
2009	0.2642%
2010	0.2578%
2011	0.2577%
2012	0.2619%
Average	0.2548%

The kW/kWh ratio is calculated by taking the annual kW for the GS>50kW rate class and dividing it by the kWh recorded at the meter for the same period.

3.0 – VECC – 16

Reference: Exhibit 3, Tab 1, Schedule 5, page 2

a) If 2012 was an anomaly, why not determine the historical average without this year's value?

Answer: If only the results of 2012 are excluded, the value returned seems to be a bit high as average demand rises to 50,061 kW per year. 2010 was the only year that the demand average was higher than 50,000 kW. 2010's high demand also seems to be an anomaly. See recalculation below:

Embedded Distributor
kW Demand & kWh Consumption

Year	2002 - 2012		2002 - 2011	
	kW	kWh	kW	kWh
2002	29,357	15,328,897	29,357	15,328,897
2003	43,882	20,418,901	43,882	20,418,901
2004	40,502	19,486,436	40,502	19,486,436
2005	43,934	16,865,800	43,934	16,865,800
2006	45,564	21,112,323	45,564	21,112,323
2007	49,752	22,263,925	49,752	22,263,925
2008	48,353	22,427,621	48,353	22,427,621
2009	49,918	22,622,442	49,918	22,622,442
2010	53,144	24,190,281	53,144	24,190,281
2011	49,139	21,309,995	49,139	21,309,995
2012	37,867	17,590,424	-	-
Total	*491,411*	*223,617,046*	*453,545*	*206,026,622*
Averages	44,674	20,328,822	50,061	22,562,853

3.0 – VECC –17

Reference: Exhibit 3, Tab 1, Schedule 8, page 1

a) Please explain further why the customer contracting for the OPA's DR3 program resulted in no standby charges.

Answer: Standby Charges are calculated as the difference between the facility's overall monthly peak and the monthly peak as measured by the load meter multiplied by KWHI's distribution rate. The intent of the charge is to compensate KWHI for lost revenue resulting from the customer generating at the time of its peak, and thus reducing distribution charges on the bill despite KWHI having to maintain plant in place to meet that peak. In essence, KWHI is "standing by" to deliver the customer's peak even when the customer doesn't need it.

Since 2010, there have not been any instances where the customer's plant peak was set during a DR3 event or any other period where its generator was in operation.

b) Will the customer be participating in DR3 in 2014? If not, why are there assumed to be no standby charges?

Answer: The customer recently re-signed as a participant in DR3 with one of the provincial aggregators. It is KWHI's understanding the contract is multi-year past 2014.

3.0 – VECC – 18

Reference: Exhibit 3, Tab 1, Schedule 9, page 1

a) Please provide the 2013 year to date Other Revenues at the level of detail set out in Table 3-48 and provide the 2012 values for the same period.

Answer: See table below. Note that account 1576 – Accounting Changes Under CGAAP will not be recorded until December 2013.

Summary of Other Revenue
2012 - 2013

January - August

Revenue Type	August 2012	August 2013
Other Regulatory Debits		
Accounting Changes Under CGAAP	$0	$0
Other Revenue		
SSS Administration Charges	164,228	168,915
Retailer Services Revenue	44,123	34,912
Late Payment Charge	162,939	161,595
Specific Service Charges	168,163	173,235
Other Distribution Revenue	390,633	540,369
Other Income and Deductions **	601,752	396,237
CDM (OPA) Revenues (net)	115,820	(85,221)
Gross Other Revenues	1,647,657	1,390,041
Fixed Asset Gains/Losses @ 50%	(34,134)	(5,840)
Remove Variance Account Interest	(72,604)	(102,986)
Adjusted Other Revenue	1,540,920	1,281,215

** Note Other Income & Deductions includes $84,800 for Contributed Capital Deferred Revenue subsequently reversed as MIFRS was not fully adopted in 2012.

b) Does Kitchener have any micro-fit customers? If yes, how many were there in 2012; how many are forecast for 2013 and 2014; and where are the revenues reported in Table 3-48?

Answer: **KWHI had a total of 222 micro-FIT customers connected as of December 31, 2012. KWHI forecasts an additional 100-120 micro-FIT customers will be connected in 2013 and another 100-120 in 2014 (Reference: Exhibit 2 Tab 7 Schedule 1).**

As per the FAQ issued by the Board in December 2010, KWHI has included microFIT revenues in account 4235 – Miscellaneous Service Revenues. The detail is shown in Table 3-51 of the documentation. In Table 3-48, the microFIT revenues are embedded in the totals for Specific Service Charges, which are also recorded to account 4235.

3.0 – VECC –19

Reference: Exhibit 3, Tab 1, Schedule 9, pages 5-8

a) Are separate charges applied to both the disconnect and the reconnect activities or does the proposed charge cover both activities?

Answer: **No, charges are only applied to the reconnection activity.**

b) Please confirm that the after regular hours charge only applies if a reconnection is requested after regular hours and does not apply if only the disconnection is done after hours.

Answer: **KWHI does not perform collection disconnections after hours therefore charges, as stated above, only occur for reconnection.**

c) Please confirm that there are no "credit agency costs" associated with Kitchener's proposed Credit Reference/Check charge.

Answer: **This is for internal costs and do not include "credit agency costs".**

End of Exhibit Three Interrogatories

Board Staff Exhibit Four Interrogatories

Exhibit 4 – Operating Expenses

4-Staff-18 Ref: Exhibit 4/Tab 1/Schedule 2/page 6 – Inflation

On page 6 of this exhibit, KWHI documents that it has used the following inflation rates in its operating expense derivation:

Year	2010	2011	2012	2013	2014
Inflation Rate (%)	1.3	2.0	2.1	1.6	2.0

a) Is this inflation rate for labour, non-labour (i.e., materials) or both?

Answer: This is the inflation factor for materials. The inflation factor for labour is as per the collective agreement and is 2.8% for 2013 and 2.85% for 2014.

b) What is the definition and data source of this inflation rate? What is the basis for the forecast for 2014?

Answer: The 2.0% inflation rate for 2014 is as per the direction given to managers at budget time. The source of the information is a best guess estimate at the time the budget was struck. The rate used for 2013 is as per the Boards inflation factors for 2013. 2014 distribution expenses will need to be adjusted to the January 1st inflation rate of 2.2% prior to finalizing the distribution rates determined by this application: See table below:

Year	2010	2011	2012	2013	2014 May
Inflation Rate (%)	1.3	1.3	2.0	1.6	2.0

http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Applications%20Before%20the%20Board/Electricity%20Distribution%20Rates/3rd%20Gen%20Stretch%20Factors

4-Staff-19 Ref: Exhibit 4/Tab 1/Schedule 2 – Drivers of OM&A Increases

I

Table 4-5, KWHI documents the drivers for the increases in OM&A expenses by year from 2010.

a) General Salary Increases is shown as one factor, while Inflation is shown as a separate factor.

i. Please identify whether cost of living increases that may be part of a labour agreement or are part of annual increases for non-union staff are reflected under General Salary Increases or are shown under Inflation.

Answer: There are no cost of living provisions in the labour agreement or for non-union staff. All wage adjustments are reflected under general salary increases

ii. The largest incremental increase for inflation is shown as $275,929 for the 2014 test year. Please explain this increase.

Answer: Table 4-5 – Cost drivers have been re-filed as part of this interrogatory process. Please see Appendix 2-J of the Filing Requirements

b) KWHI documents that the decision from its stand-alone Smart Meter Application EB-2012-0288 has an incremental impact of $1,084,463 in 2012, and forecasts further incremental OM&A expenses of $354,000 for 2013 and $351,900 for 2014. Please provide further explanation of the further incremental increases in OM&A due to smart meters for each of 2013 and 2014.

Answer: Please See 4- Energy Probe –30 and 4-Energy Probe-37 for detailed explanations of the costs for 2012, 2013, and 2014.

4-Staff-20 Ref: Exhibit 4/Tab 2/Schedule 2 and Appendix 2-J – Monthly Billing

On page 4 of this exhibit, KWHI states that it is planning to move to monthly billing, and provides the following table:

		2013	2014
Billing and Collecting			
	Postage	35,000	65,000
	Office Supplies	13,000	13,000
Customer Service			
	Postage	136,000	266,000
	Office Supplies	38,000	72,000
Total		**222,000**	**416,000**

a) What is the status of KWHI's move to monthly billing?

Answer: KWHI has commenced the analysis and planning to enable the changes to its Customer Information System to accommodate monthly billing.

b) KWHI states that monthly billing is being done "to assist customers with cash flow concerns due to rising electricity bills". Monthly billing should also aid KWHI's cash flow and hence reduce its cash working capital requirements. How has KWHI taken the move to monthly billing into account in determining its working capital allowance?

Answer: **Since KWHI did not complete a lead/lag study, KWHI is unable to determine the impact on working capital requirements resulting from moving to monthly billing from bi-monthly billing.**

c) Please explain the table above. Are these total OM&A expenses or incremental OM&A due to monthly billing?

Answer: **The above table is meant to show the incremental expenses of Postage and Office Supplies for the years 2013 (6 months) and 2014 (12 months). The corrected table should be as presented in d) below.**

d) The Microsoft Excel version of Appendix 2-J documents that monthly billing is a driver of OM&A expenses with an incremental cost of $178,000 in 2013 and $164,000 in 2014. Please show the relationship between the above table and the entries in Appendix 2-J.

Answer: **Appendix 2-J as originally filed only includes Customer Service - Billing. There is a $10,000 error in 2013. The table below shows the correct amount for incremental costs that have been updated in Filings Requirements to Appendix 2-J.**

INCREMENTAL

	2013	**2014**
Customer Service - Billing		
Office Supplies	28,000	34,000
Postage	140,000	130,000
Customer Service - Collecting		
Office Supplies	5,000	6,000
Postage	28,500	30,000
	201,500	200,000

e) Please explain the difference between “Billing and Collecting” and “Customer Service”, and why the costs for “Customer Service” are significantly higher.

Answer: **The two titles should be Customer Service – Billing and Customer Service – Collecting. As well, the chart should be corrected to show the incremental impact of Monthly Billing with the correct titles. This has been updated in d) above.**

Collections costs are lower as they only capture the costs of Customers in arrears.

f) Does KWHI have, or plan to have by the end of 2014, other options for customers to receive their bills on-line to reduce paper and postage expenses? If so, are these reflected in the increased costs shown?

Answer: KWHI currently offers two on-line electronic bill presentment options. Since 2008, KWHI has offered "e-bill", KWHI's own proprietary offering. Since 2012, KWHI has contracted with Canada Post to offer "e-post" to its customers. 9.2% of KWHI's customers have taken advantage of this service. KWHI continues to work with Canada Post to encourage customers to move to on-line receipt of their bills. KWHI anticipates, by the end of 2014, an increase to 13% participation.

4-Staff-21 Ref: Exhibit 4/Tab 1/Schedule 2/Table 4-3 – Billing and Collecting

In Table 4-3, KWHI documents its OM&A expenses by account. With respect to Billing and Collecting, the increases in 2012 to 2014 are largely shown by increases over 10% per annum in Account 5315 – Customer Billing and Account 5320 – Collecting, as shown below:

Account Description	Last Rebasing Year (2010 Actuals)	2011 Actual	2012 Actual[2]	Bridge Year 2013[3]	Test Year 2014
Billing and Collecting					
5305 Supervision	$ 198,624	$ 237,871	$ 242,320	$ 256,000	$ 278,700
5310 Meter Reading Expense	$ 474,328	$ 437,507	$ 800,933	$ 529,600	$ 512,400
5315 Customer Billing	$ 1,324,913	$ 1,338,095	$ 1,414,088	$ 1,620,800	$ 1,857,200
5320 Collecting	$ 722,738	$ 772,098	$ 909,893	$ 1,063,800	$ 1,138,500
5325 Collecting - Cash Over and Short	$ 109	$ 103			
5330 Collection Charges	$ 25,764	$ 28,531			
5335 Bad Debt Expense	-$ 46,363	$ 103,015	$ 146,917	$ 147,000	$ 147,000
5340 Miscellaneous Customer Accounts Expenses		$ 2,682			
Total - Billing and Collecting	$ 2,700,114	$ 2,919,902	$ 3,514,152	$ 3,617,200	$ 3,933,800

a) Please identify the drivers of the increase in customer billing, differentiating between the move to monthly billing addressed in 4-Staff-3 above.

Answer: KWHI noticed an error with the OEB account 5320 and 5335. The corrected numbers are presented below:

Account Description	Last Rebasing Year (2010 Actuals)	2011 Actual	2012 Actual[2]	Bridge Year 2013[3]	Test Year 2014
Billing and Collecting					
5305 Supervision	$ 198,624	$ 237,871	$ 242,320	$ 256,000	$ 278,700
5310 Meter Reading Expense	$ 474,328	$ 437,507	$ 800,933	$ 529,600	$ 512,400
5315 Customer Billing	$ 1,324,913	$ 1,338,095	$ 1,414,088	$ 1,620,800	$ 1,857,200
5320 Collecting	$ 722,738	$ 772,098	$ 909,893	$ 1,023,800	$ 1,098,500
5325 Collecting - Cash Over and Short	$ 109	$ 103			
5330 Collection Charges	$ 25,764	$ 28,531			
5335 Bad Debt Expense	-$ 46,363	$ 103,015	$ 146,917	$ 187,000	$ 187,000
5340 Miscellaneous Customer Accounts Expenses		$ 2,682			
Total - Billing and Collecting	$ 2,700,114	$ 2,919,902	$ 3,514,152	$ 3,617,200	$ 3,933,800

The Drivers of the increases in Customer Service – Billing are as follows:

Customer Service Billing Drivers

	2013	2014
Opening Balance	1,414,088	1,620,800
Monthly Billing	168,000	164,000
Labour	58,604	52,000
IT	24,447	24,500
Advertising	23,397	(5,000)
Smart Meter Decision	(91,286)	-
IFRS Changes	6,905	1,200
Other	16,645	(300)
Ending Balance	1,620,800	1,857,200

b) Please identify the drivers of the increases in customer collecting expenses.

Answer: The Drivers of the increases in Customer Service – Collecting are as follows:

Customer Service Collecting Drivers

	2013	2014
Opening Balance	909,893	1,023,800
Monthly Billing	33,500	36,000
Labour	51,382	19,100
IT	15,001	15,100
Smart Meter Decision	(9,458)	
IFRS Changes	5,387	800
Other	18,095	3,700
Ending Balance	1,023,800	1,098,500

4-Staff-22 Ref: Exhibit 4/Tab 2/Schedule 8/Attachment 1 – Appendix 2-J

In the Attachment to this exhibit, the hardcopy of Appendix 2-J refers to 2012, 2013 and 2014 as being reported under MIFRS, and the 2014 OM&A is documented as $18,523,801. In the Chapter 2 Appendices filed in Microsoft Excel format on June 21, 2013, Appendix 2-J shows all years under CGAAP and the 2014 test year OM&A forecast is $18,523,200. Please confirm that the Microsoft Excel version of Appendix 2-J is the correct one corresponding to KWHI's revised Application.

Answer: Confirmed, Appendix 2-J should be $18,523,200

4-Staff-23 Ref: Appendix 2-M and Exhibit 4/Tab 2/Schedule 3 – Regulatory Costs

In Exhibit 4/Tab 2/Schedule 3, KWHI documents that it has $272,500 of one-time costs associated with the preparation of this Application, and it proposes to recover these costs over 4 years at $68,000 per year.

In the Microsoft Excel version of Appendix 2-B, KWHI provides the following table showing one-time costs for this Application:

Please fill out the following table for all one-time costs related to this cost of service application

		Historical Year(s)	2013 Bridge Year	2014 Test Year
4	Expert Witness costs for regulatory matters		$ -	$ -
6	Consultants' costs for regulatory matters	$ 61,788	$ 107,000	$ -
7	Operating expenses associated with staff resources allocated to regulatory matters	$ 55,030	$ 67,000	$ -
8	Operating expenses associated with other resources allocated to regulatory matters [1]	$ 8,352	$ 28,400	$ -
11	Intervenor costs	$ 36,888	$ 70,000	

This table documents $162,058 for historical years (pre-2013) and $272,400 for 2013. No costs are shown for 2014 as KWHI has proposed that new rates will be in place for January 1, 2014.

a) Please explain each of the costs shown for the historical year(s), including how these are one-time costs associated with this current cost of service Application.

Answer: The costs include in the historical years column are the actual one-time costs incurred to file the 2010 Cost of Service application. They are being amortized over four years and end in December 2013. None of these costs are related to this Cost of Service.

b) How are the historical year costs, before 2013, being recovered in KWHI's Application?

Answer: Historical year costs are not being recovered in this 2014 Cost of Service Application.

c) Please confirm that the operating expenses for internal KWHI staff and resources being allocated as one-time costs for this Cost of Service Application are incremental to the normal OM&A budget recovered in existing distribution rates.

Answer: Confirmed. Incremental overtime staff costs and resources only are recovered as a one- time cost to this Cost of Service application.

4-Staff-24 Ref: Exhibit 4/Tab 3/Schedule 1 – Information Technology Expenses

On pages 15 to 19 of this exhibit, KWHI documents the annual expenses for Information Technology. KWHI documents the following for I.T. expenses by year.

Activity	2010	2011	2012	2013	2014
	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Information Technology	1,190,006	1,266,025	1,277,076	1,543,800	1,811,500

KWHI explains that the expenses include salary increases of about $40.2K for 2013 and $59.2K for 2014. Even taking these into account, the year-over-year increases for 2013 and 2014 would exceed the materiality threshold of $175K.

a) Please provide further explanation of the IT projects documented on page 16 associated with the increases for 2013 and 2014.

Answer: IT charges are allocated to the various business units. Because each business unit picks up a portion of the IT charges, and in each department the increase in IT charges was not greater than the level of materiality, the projects that made up the IT charges were not explained. In 2013 KWHI expects an increase of $70K for salaries stemming from economic wage increases as well as the succession planning addition during the year of a new Systems Analyst. Other increases include a planned network security audit ($20K), and higher costs associated with the expanded Internet bandwidth agreement and diverse route connection ($15K) required to support increased traffic volume for smart meter AMI, MDM/R and ODS system interfaces. A significant price increase announced by Microsoft as well as additional MS SQL Server licensing will contribute $42K to increase software costs. A new agreement with Sungard Availability Services signed late 2012 for enhanced Data Centre backup and disaster recovery capability will result in cost increases of $66K in 2013.

In 2014, KWHI again expects increases of $59.2K in salaries from economic increases as well as increased software maintenance costs for a new Outage Management System installation ($80K) as well as software maintenance costs for a new Customer Information System ($40K) anticipated in 2014.

b) Please provide the year-to-date and the estimate for 2013 year-end for Information Technology expenses based on the work and projects being done this year.

Answer: See table below:

	2013 Budget	2013 August Year To Date	2013 Forecast to Year End
IT	1,543,800	943,962	1,427,000

4-Staff-25 Ref: Exhibit 4/Tab 4/Schedule 1 and Appendix 2-K

KWHI documents that it expects to have a Full-time Equivalent complement of 177 by December 31, 2014. KWHI also notes that, in addition, it employs a number of co-op students in various departments. KWHI notes that 13 co-op students are hired to develop the necessary skills and that, particularly for certain skilled positions, such as for Powerline Technicians, KWHI would to be able to hire some as part of succession planning for retiring employees.
On page 8 of this exhibit, KWHI states:

> KWHI's employee complement, compensation and benefits are set out in Appendix 2 - K. Appendix 2 - K reports the actual wages and salaries paid, rather than the general ledger balances and does not include members of the Board (Directors), temporary employees or students.

Please complete Appendix 2-K documenting the all employee complement and compensation representing the complete full-time equivalent employees based on all full-time and part-time employees, including co-op students. KWHI may wish to use the amended Appendix 2-K as issued with the Filing Requirements for Transmission and Distribution Applications issued on July 17, 2013.

Answer: Appendix 2-K is being re-filed at this time. It is noted that the part time and co-op students were not included, but in KWHI's analysis of Appendix 2-K, it noted that it erroneously included costs for its CDM staff, which should not have included as CDM staff are not a cost to KWHI. In summary, the re-filed Appendix 2-K now includes part-time and summer and co-op students, but has been reduced by the amounts for CDM staff. Also, it is in the new filing requirement format.

4-Staff-26 Ref: Exhibit 4/Tab 7/Schedule 1/Table 4-21

The Board issued updated Filing Requirements for Transmission and Distribution Applications, and associated Microsoft Excel spreadsheet Appendices on July 17, 2013. In the updated Appendices, the instruction for using Appendix 2-C CGAAP tab in documenting depreciation expense, states:

> If an applicant chooses to remain on CGAAP or adopt ASPE and make the capitalization and depreciation expense policies in 2012, the applicant must complete Appendix 2-CN to Appendix 2-CQ (inclusive).

KWHI provided the depreciation expenses for 2009 to 2014 under CGAAP in Table 4-21. However, KWHI has not provided the supporting calculations of the depreciation expenses in each year in Appendices 2-CN to 2-CQ.

Please complete and file Appendices 2-CN to 2-CQ and reconcile the amounts with Table 4-21.

Answer: KWHI attaches the required Appendices in the attached Excel File "Filing Requirements Chapter 2 Appendices for 2014". The depreciation in Table 4-21 matches the

depreciation per Appendix 2-B Column K as filed June 21. This is also the same depreciation in Appendix 2-CO (2012), Appendix 2-CP (2013) and Appendix 2-CQ (2014).

KWHI notes that in Appendix 2-CO the Smart Meter Decision affects the variance column M. Therefore KWHI has put the depreciation as per the Smart Meter Decision (EB-2012-0288) into columns H, K and N. On Appendix 2-CP, KWHI has continued with the Smart Meter Decision and put the allowed Depreciation Expense as per the decision in columns H and L.
The variance on Appendix 2-CO relates to the Smart Meter Decision and not taking the half year depreciation in 2012.

The variance on Appendix 2-CP relates to the half year rule not being taken and the effects of rounding. In account 1808, KWHI erred in its depreciation calculation and did not take depreciation on its additions in 2013 and 2014.

The variance on Appendix 2-CQ relates to the effects of rounding. In account 1808, KWHI erred in its depreciation calculation and did not take depreciation on its additions in 2013 and 2014.

4-Staff-27

Ref: PILS Work Form for 2013 Filers: Adjusted Taxable Income-Bridge Year Tab and Chapter 2 Filing Requirements for Electricity Distribution Rate Applications, S.2.7.5, p.33, dated July 17, 2013

The 2014 COS Filing Requirements state:

> Regulatory assets (and regulatory liabilities) should generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.
>
> In the Income Tax/ PILs Work Form: Adjusted Taxable Income-Bridge Year Tab, KWHI included under "Other Additions" the amount of $3,676,200 for Account 1576 which is not consistent with the COS Filing Requirements. The amount of $3,676,200 for Account 1576 should not be included under the "Other Additions".

Please remove the Account 1576 amount of $3,676,200 from the Adjusted Taxable Income – Bridge Year, "Other Additions" (PILS Work Form) and file the revised Adjusted Taxable Income for the Bridge Year Tab.

Answer: KWHI has removed the $3,676,200 from Schedule 1. Prior to June 25, 2013, account 1576 balances were to be accounted for as a direct reduction to the revenue requirement for the years 2014 – 2017. Since the time that KWHI filed its 2014 rate application, the process to be followed for account 1576 has changed and is now to be calculated as a rate rider. KWHI

quotes (from its rate filing) its reasons for removing the amount of $3,676,200 as a Schedule 1 adjustment below:

"Schedule One Adjustment for Account 1576/4305 in 2013
KWHI has recorded a Schedule One adjustment for the amount recorded to account 1576/4305 in 2013. This amount is an increase to taxable income for 2013 of $3,676,200.
KWHI believes that the Schedule One adjustment is necessary as the entry recorded to account 4305 in 2013 is a reduction to revenue (to recognize the change to capitalization policies resulting from the change to New GAAP). As per Board direction, KWHI also recorded this regulatory entry in 2012. The amount recorded in 2012 was $2,265,213. The offset to 4305 – Regulatory Debits was account 1576 – Accounting Changes Under GAAP. The ending balance of account 1576 as the end of 2013 is forecasted to be a credit $5,941,413.

The Board has directed Cost of Service applicants to amortize the balance of account 1576 over the rebasing cycle of 4 years as a reduction to the revenue requirement for the test year. The resulting reduction to KWI's revenue requirement is $1,485,353 for each year for the four year period 2014 through 2018.

KWHI submits that the Schedule One adjustment is necessary in order to not "double dip" by taking the regulatory deduction twice by reducing net income in both 2013 and then again for each year from 2014 through 2017."

Now that the filing requirements have changed, KWHI submits that the $3,676,200 adjustment is no longer necessary and its removal from the Adjustments to Taxable Income is appropriate. The table is adjusted below:

Determination of Tax Adjustments to Accounting Income for 2013

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Amortization of tangible assets	104	7,705,054	0	7,705,054
Loss on disposal of assets	111	0	0	0
Non-deductible meals and entertainment expense	121	22,000	0	22,000
Reserves from financial statements- balance at end of year	126	0	0	0
Federal ITC re SR&ED Credit 2012		36,273	0	36,273
Federal Apprenticeship 2012		2,730	0	2,730
ORDTC (proxy portion)		2,472	0	2,472
Other Additions - Ontario Apprentice & Co-op Education Tax Credits	295	56,000	0	56,000
Total Additions		**7,824,529**	**0**	**7,824,529**
Deductions:				
Gain on disposal of assets per financial statements	401	30,000	0	30,000
Capital cost allowance from Schedule 8	403	13,481,900	0	13,481,900
Total Deductions		**13,511,900**	**0**	**13,511,900**
Other Adjustments to Taxable Income				
Charitable donations from Schedule 2	311	1,000	0	1,000
Total Adjustments		**1,000**	**0**	**1,000**
Tax Adjustments to Accounting Income		**(5,686,371)**	**0.00**	**(5,686,371)**

KWHI's 2013 taxable income is calculated below:

2013 Taxable Income

Description	2013 Bridge Actual
Revenue:	
Revenue Deficiency	
Distribution Revenue	38,163,923
Other Operating Revenue (Net)	1,840,800
Accounting Changes Under CGAAP - Account 1576	(3,676,200)
Total Revenue	**36,328,523**
Costs and Expenses:	
Administrative & General, Billing & Collecting	6,805,075
Operation & Maintenance	10,626,000
Depreciation & Amortization	7,169,353
Property Taxes	376,000
Deemed Interest	6,801,351
Total Costs and Expenses	**31,777,778**
Utility Income Before Income Taxes	**4,550,744**
Income Taxes:	
Corporate Income Taxes	
Total Income Taxes	
Utility Net Income	**4,550,744**
Capital Tax Expense Calculation:	
Total Rate Base	201,820,490
Income Tax Expense Calculation:	
Accounting Income	4,550,744
Tax Adjustments to Accounting Income	(5,686,371)
Taxable Income	**(1,135,627)**

4-Staff-28 Exhibit 4/Tab 8/Schedule 1 – Discussion Regarding the PILs Calculation

In this exhibit, KWHI discusses the issue that it sees has arisen due to the change in depreciation rates, which generally widens the gap between depreciation rates for financial reporting and rate-setting purposes, and the Capital Cost Allowance (“CCA”) rates used for tax calculations. In the short term, this results in reductions to taxable income, estimated at about ($2M) for 2013 and ($6M) for 2014, and hence reduced estimated PILs expenses. These reductions are beyond the impacts of reductions to corporate income tax rates since KWHI’s last cost of service application.

In addition to its analysis, on pages 15-16 of this exhibit, KWHI makes several conclusions and proposals on this issue.

a) What specific approvals is KWHI seeking from the Board in this application? If KWHI is seeking an accounting order, please provide KWHI's proposed draft accounting order.

Answer: KWHI is not seeking any specific approvals in this application. KWHI was observing the widening gap between depreciation allowable for GAAP purposes and taxation purposes and the resulting dramatic reduction to PILS payable. This reduction would generally apply to all corporations in Canada transitioning to IFRS. The result would be significantly lower income tax revenues for government. KWHI wanted the Board to be aware that this could become an issue in the future as government may wish to change tax law in the future to increase revenues.

As it stands under current regulatory practice, account 1592 – PILS & taxes variance for 2006 & subsequent years – can only be cleared when an LDC files a Cost of Service application. KWHI recognizes the impact this could have on cash balances for all LDCs if tax laws were amended to bring tax revenues back up to pre-IFRS amounts. LDCs could request annual clearance of account 1592 (as a Type 1 variance account) if such an amendment was to occur.

b) CCA rates are set by the Canada Revenue Agency pursuant to the Federal *Income Tax Act*. On what basis does KWHI make the statement "it would seem possible that the Ontario Energy Board Act could be revised to include revised CCA rates for PILS"? What is KWHI proposing with this statement?

Answer: KWHI is not proposing anything specific with the statement. KWHI was observing the widening gap between depreciation allowable for GAAP purposes and taxation purposes and the resulting dramatic reduction to PILS payable. This reduction would generally apply to all corporations in Canada transitioning to IFRS. The result would be significantly lower income tax and PILS revenues which might force federal and provincial governments to propose changes to CCA rates in order to recoup lost revenues resulting from the change to IFRS.

End of Board Staff Exhibit Four Interrogatories

Energy Probe Exhibit Four Interrogatories

4-Energy Probe-29

Ref: Exhibit 4, Tab 1, Schedule 1 &
Exhibit 6, Tab 1, Schedule 1 &
Exhibit 4, Tab 1, Schedule 2

At page 1 of the Exhibit 4, Tab 1, Schedule 1 evidence it is indicated that controllable expenses increased by $1.6 million due to the adoption of modified CGAAP in 2012. An analysis of Table 6-3 in Exhibit 6, Tab 1, Schedule 1 shows a difference of $1,593,886.

a) Table 4-5 in Exhibit 4, Tab 1, Schedule 2 shows a cost driver in 2012 for accounting changes of $1,227,168. Please reconcile this figure with the $1,593,886 noted above and indicate which figure is the actual impact in 2012 due to the adoption of modified CGAAP.

Answer: Table 4-5 is looking at the impact year over year of the accounting changes. Table 6-3 compares the two standards. The overall effect to distribution expenses due to the adoption of modified CGAAP is $1.7 million, rather than the figures quoted above. The breakdown of expenses is seen in the below table and presented as Table 10-7 in the original application:

	CGAAP (modified)	CGAAP (pre-2012)	Variance
Net Income	9,172,686	9,259,451	(86,765)

Changes to Net Income

Changes to Net Income	CGAAP (modified)	CGAAP (pre-2012)	Variance
Labour Overhead	(1,361,482)	1,608,783	247,301
Vehicle Overhead	(806,514)	1,231,715	425,201
Supervisory Overhead	(123,732)	247,342	123,611
Material Overhead	(29,610)	86,267	56,657
6400 - Employee Benefits	(966,645)	855,570	(111,075)
5350 - Information Technology	(998,291)	995,051	(3,240)
6475 - Service Centre Building Maintenanc	-	126,094	126,094
5617 - Human Resources	7,975	(67,918)	(59,943)
6492 - Safety	(421,819)	-	(421,819)
6498 - Allocation of Garage Expenses	(871,167)	-	(871,167)
8030 - Purchasing/Warehouse	(378,435)	-	(378,435)
Allocation of BU 6499	72,830	(38,430)	34,400
Total Effect of Overhead/Burden Change	(5,876,889)	5,044,474	(832,416)
Reallocation of Engineering	(626,084)		(626,084)
Reallocation of Wages to Expense	-	(233,837)	(233,837)
Total Effect on Distribution Expense	**(6,502,973)**	**4,810,637**	**(1,692,337)**
Amortization		3,870,787	3,870,787
	(6,502,973)	8,681,424	2,178,450
Variance is account 1576			(2,265,215)

The adoption of modified CGAAP also decreased depreciation expense by $3.9 million and the net effect of the change in amortization is the number presented in the table above.

b) Is the figure provided in the response to part (a) a good proxy for the difference between CGAAP and modified CGAAP for 2013 and 2014? If not, please provide an estimate of the increase in OM&A in each of 2013 and 2014 as the result of the adoption of modified CGAAP in 2012.

Answer: The $1.7 million presented in a) above is a reasonable proxy albeit a little bit low. KWHI has converted its financial transactions to August 2013 and the increase to distribution expenses is $1.2 million year-to-date. If this is extrapolated over 12 months (assuming expenses are incurred evenly), the increase to distribution expenses to December 31, 2013 would be $1.85 million.

4-Energy Probe-30

Ref: Exhibit 4, Tab 1, Schedule 1

Table 4-5 reflects an increase in the 2012 OM&A costs for the smart meter decision of $1,084,463.

Please break this amount down by the year the costs were actually incurred.

Answer: See table below:

	2009	2010	2011	Apr-12		Dec-12	
Operations	55,514	50,985	245,228	301,363	653,091	(143,353)	509,737
Billing & Collecting	93,784	102,333	158,959	24,647	379,723	143,353	523,076
Admin	13,333	9,106	2,731	26,479	51,649	-	51,649
	162,631	162,424	406,919	352,490	1,084,463	-	1,084,463

4-Energy Probe-31

Ref: Exhibit 4, Tab 1, Schedule 1

At the bottom of page 1, KWHI indicates that the total allowable operating costs will increase by 1.1% between the Board approved level for 2012 and the forecast for 2014.

a) Please confirm that this increase includes the impact of depreciation expenses.

Answer: Confirmed – this includes the impact of depreciation

b) What is the increase between the Board approved 2010 level and the forecast for 2014 excluding depreciation costs (i.e. controllable OM&A costs plus property taxes)?

Answer: The increase is $4,515,879 or 23.9%

4-Energy Probe-32

Ref: Exhibit 4, Tab 1, Schedule 1 & RRWF

Please reconcile the OM&A figure for 2014 of $18,523,200 shown in Table 4-1 with the figure of $18,523,800 used in the RRWF.

Answer: The most recent version of the RRWF (filed August 9, 2013) uses the figure $18,523,200 which coincides with Table 4-1.

4-Energy Probe-33

Ref: Exhibit 4, Tab 1, Schedule 2 &
Exhibit 4, Tab 1, Schedule 1

a) Please confirm the following differences between Table 4-3 and Table 4-1:
i) Administrative and General lower by $61,322 in Table 4-3 for 2009;

Answer: **Table 4-1 inadvertently included $61,322 for charitable donations in 2009.**

ii) Community Relations lower by $47,465 in Table 4-3 for 2011;

Answer: **Table 4-1 inadvertently had the LEAP donation in two places.**

iii) Community Relations lower by $46,465 in Table 4-3 for 2012: and

Answer: **Table 4-1 inadvertently had the LEAP donation in two places.**

iv) Administrative and General lower $5,422 in Table 4-1 for 2012.

Answer: **Table 4-3 is correct, Admin and General should be $2,663,711.**

b) Please explain each of the differences noted above in part (a) or as corrected in part (a).

Summary of Operating Costs

OM&A Expenses	2009 Actual CGAAP	2010 Board Approved CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2012 Actual CGAAP	2013 Bridge CGAAP	2014 Test CGAAP
Operation	2,815,696	3,051,200	2,824,720	3,258,635	4,821,308	5,365,500	5,642,000
Maintenance	3,953,941	4,761,500	4,069,611	4,856,219	5,226,753	5,260,500	5,619,400
Billing and Collections	2,883,410	3,003,200	2,700,114	2,919,903	3,514,152	3,617,200	3,933,800
Community Relations	227,140	209,400	212,185	*198,222*	*164,909*	236,675	237,300
Administrative and General Expenses	*2,323,216*	2,856,203	2,464,329	2,444,036	*2,663,711*	2,951,200	3,090,700
Total Controllables	**12,203,402**	**13,881,503**	**12,270,958**	**13,677,015**	**16,390,833**	**17,431,075**	**18,523,200**
Property Tax	258,390	520,618	390,054	371,636	352,736	376,000	394,800
Amortization Expenses	9,386,316	10,317,027	9,798,634	10,114,321	9,661,969	7,169,353	6,077,499
Total OM&A Expenses	**21,848,109**	**24,719,148**	**22,459,645**	**24,162,971**	**26,405,539**	**24,976,428**	**24,995,499**

Answer: **Table 4-1 has been updated as above for the changes. Table 4-3 was correct as filed**

c) Are some or all of the differences related to expenses that are not recoverable for regulatory purposes? If this is the case, please provide a revised Table 4-1 that only included recoverable expenses for regulatory purposes. Please **also provide** a revised Table 4-5 that only includes recoverable OM&A costs for regulatory purposes.

Answer: Table 4-1 inadvertently included donations that were not recoverable for regulatory purposes. The revised Table 4-1 is attached above.

d) Please provide the most recent year-to-date figures available for OM&A expenses in the same level of detail as found in Table 4-1 (excluding property tax and amortization). Please provide the figures for the corresponding period in 2012. In doing so, please do not include any cost incurred prior to 2012, but included in the 2012 OM&A expense, as a result of the smart meter decision.

Answer:

Summary of Operating Costs

OM&A Expenses	2012 YT August CGAAP	2013 YT August CGAAP
Operation	2,786,683	3,497,474
Maintenance	3,665,794	3,547,140
Billing and Collections	2,033,335	2,052,684
Community Relations	*497,387*	215,538
Administrative and General Expenses	*2,021,906*	1,963,862
Total Controllables	**11,005,104**	**11,276,698**

4-Energy Probe-34

Ref: Exhibit 4, Tab 1, Schedule 2

a) Please provide the source for the historical inflation rates shown on page 6.

Answer: See 4-Staff-18 b)
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Applications%20Before%20the%20Board/Electricity%20Distribution%20Rates/3rd%20Gen%20Stretch%20Factors

For 2014 it was the direction provided to managers when setting their budgets.

b) Please provide the source for the forecasted inflation rates for 2013 and 2014 shown on page 6.

Answer: See the link below on the Ontario Energy Board Website
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Applications%20Before%20the%20Board/Electricity%20Distribution%20Rates/3rd%20Gen%20Stretch%20Factors

For 2014 it was the direction provided to managers when setting their budgets.

c) Please provide the annual inflation rates based on the GDPIPIFDD for 2010 through 2012 (Statistics Canada V62307283, Matrix 380-0066).

Answer: **2010 1.0**
2011 2.3
2012 1.9

d) Please provide the annual inflation rates based on the GDPIPIFDD for 2010 through 2012 (Statistics Canada V62307283, Matrix 380-0066).

Answer: **See response to c)**

e) Please provide the quarterly year-over year inflation rate for each quarter of 2013 that is currently available (i.e. Q1 2013 vs. Q1 2012, etc.) from the same source referenced in part (c) above.

Answer: **See below:**

Q1 2010	104.2	
Q2	104.5	
Q3	105.0	
Q4	105.5	
Q1 2011	106.2	2.0
Q2	106.8	2.3
Q3	107.6	2.6
Q4	108.3	2.8
Q1 2012	108.7	2.5
Q2	109.1	2.3
Q3	109.3	1.7
Q4	109.5	1.2
Q1 2013	110.1	1.4
Q2	110.3	1.2

f) The inflation rate for 2013 is shown as 1.6% and that for 2014 is shown as 2.0%. However, the inflation figure shown in Table 4-5 for 2014 is nearly double the amount shown for 2013. Please reconcile and show the calculation of the inflation cost drivers for each of 2011 through 2012.

Answer: **The cost driver table (Filing Requirements Appendix 2-J) is being re-filed at this time. The inflation factor as previously filed included inflation and other factors to arrive at the required total expense number. This has been broken out in the revised table to show the difference between inflation and other minor cost drivers.**

4-Energy Probe-35

Ref: Exhibit 4, Tab 2, Schedule 2

a) What would the increase in payroll costs for 2014 be if the increases for 2012, 2013 and 2014 were reduced to 2.0% per year?

Answer: **2012 $147,343**
2013 $157,199
2014 $160,786

b) What percent increases were given to management employees and other non-unionized employees in each of 2009 through 2012, and what is the forecast for 2013 and 2014?

Answer: **Management receives the same increase as negotiated for union staff.**

April 2009	**3.00%**
April 2010	**3.00%**
April 2011	**3.00%**
April 2012	**2.75%**
April 2013	**2.80%**
April 2014	**2.85%**

d) Please provide the dollar impact of the increases from part (b) above for each year, similar those calculated for unionized employees on pages 1 and 2.

Answer: **Payroll increases as calculated include inside union, management and outside union employees. The figures in part a) and in Exhibit 4, Tab 2, Schedule 2 include all staff.**

4-Energy Probe-36

Ref: Exhibit 4, Tab 2, Schedule 2 &
Exhibit 4, Tab 1, Schedule 2

a) Please explain why there are no reductions shown in 2013 or 2014 in Table 4-5 related to the diversion of resources to OPA programs, as explained on page 3 of Exhibit 4, Tab 2, Schedule 2.

Answer: **This was omitted in the schedule please see the revised cost Driver table in 4-Energy Probe-34**

b) Please provide details on the fully allocated costing methodology used to allocate costs to the OPA programs.

Answer: The CDM business unit is 5415 in KWHI's accounting records. OPA programs are recorded to business unit. Costs are allocated to 5415 based on the resources used.

Purchasing - Business unit 5415 picks up its share of its costs from the purchasing department based on the total of purchase orders issued on its behalf. In 2012, this represents 4% of the total purchasing department costs.

Utilities - Business unit 5415 is allocated a percentage of the utilities expenses based on the square footage of the space in the building that they occupy. This is less than 1% of total utility costs in 2012.

Building Operations – The total expenses of operating the building are allocated to business unit 5415 based on total inside staff. The annual allocation is 7%.

Identifiable costs are allocated to the business unit as required. Examples of identifiable costs are vehicle depreciation, travel expenses.

Other allocations include Safety, HR, IT and Warehouse allocations. IT is allocated as a cost per workstation.

c) What is the total cost allocated to OPA programs in the 2014 test year?

Answer: $294,850. See detail below:

Expense	2014 Test
Labour & Labour Overhead	165,650
Material Overhead	100
Indirect Warehouse Allocation	11,500
Information Technology Charges	51,100
Utilities Expense	1,500
Insurance Expense	1,200
Depreciation Expense	9,500
Safety Expense Allocation	5,100
HR Expense Allocation	2,800
Administration Charges	46,400
	294,850

4-Energy Probe-37

Ref: Exhibit 4, Tab 2, Schedule 2

a) Please explain the incremental costs for smart meters shown in Table 4-5 for 2013 and 2014 of $345,000 and $351,900, respectively. What are the amounts included in 2012 associated with the noted cost drivers: meter reading fees, data systems and software maintenance costs.

Answer: See below:

	2012	2013	2014
Meter Reading Fees	101,286	184,000	187,680
Data Sysems	144,129	130,000	132,600
Software Maintenance	21,590	31,000	31,620
	267,005	345,000	351,900

b) The figures imply that in 2014, smart meter related OM&A costs will be $1,781,363 ($1,084,463 + $345,000 + $351,900). Please confirm that this is accurate, and explain how this is possible given that the $1,084,563 figure includes expenses incurred prior to 2012. If not, please provide the total smart meter related OM&A costs for the 2014 test year.

Answer: The incremental costs for 2013 and 2014 are $345K and $352K respectively. The incremental increase for 2014 vs 2013 is $7K.

KWHI made an error in its original Table 4-5 in E4T1S2. Table 4-5 is being resubmitted as part of the interrogatory process (See 4-Energy Probe-34).

4-Energy Probe-38

Ref: Exhibit 4, Tab 2, Schedule 2

The evidence indicates that KWHI is moving to monthly billing in 2013 in order to assist customers with cash flow concerns due to rising electricity bills.

a) Has KWHI moved to monthly billing? If not, why does KWHI expect to move to monthly billing?

Answer: KWHI has commenced the analysis and planning to enable the changes to its Customer Information System to accommodate monthly billing.

b) Does the move to monthly billing assist KWHI with its cash flow? If not, please explain fully.

Answer: KWHI did not complete a lead/lag study so it is unable to quantify the effects on cash flow.

c) KWHI is forecasting an increase in collection expense. Please explain why this expense continues to rise despite the efforts to assist customers with their cash flow concerns.

Answer: There are a number of reasons for this including:

- **Customer growth**
- **Continued difficult economic conditions in Waterloo Region**
- **Inability to collect and retain security deposits**
- **Initiatives to assist low income customers prolong the collections process**
- **Although monthly billing will provide a more frequent and smaller bill, there will still be segments of our customer base that do not pay on time and attempt not to pay at all. Associated with late payments, we produce and issue reminder letters, and we expect that more of these will be issued with monthly billing. Although we expect the percentage to fall because of smaller bill amounts, they will be issued 12 times per year rather than 6 and so we expect the number will increase and have budgeted for a partial year of increased paper, envelopes and postage in 2013, and a full year in 2014. For those payments that remain uncollected we issue termination orders and hand-deliver them to customer premises, and for some portion of those accounts, we perform service disconnections. Once again, we expect fewer to be issued with each cycle, but each cycle will occur twice as often, so our overall numbers have increased.**
- **There is a staff member returning from maternity leave and so labour costs have increased over the temporary labour costs in 2013.**

d) KWHI is not forecasting a decrease in bad debt expense. Please explain why there is no decrease despite the efforts to assist customers with their cash flow concerns.

Answer: KWHI has hired more staff for Collections (See Ex4, T4, S1). As well the cost of IT continues to rise (See Staff 4-Staff-24). With monthly billing, it is anticipated that the frequency of KWHI's collection activities will also increase.

4-Energy Probe-39

Ref: Exhibit 4, Tab 2, Schedule 2

In the paragraph related to the Service Centre on page 5, the last sentence ends with "and are not 100% charged to OM&A". Should "not" be "now"?

Answer: Yes

4-Energy Probe-40

Ref: Exhibit 4, Tab 2, Schedule 8 &
Exhibit 4, Tab 1, Schedule 1 &
Exhibit 4, Tab 1, Schedule 2

a) Are the non-recoverable amounts shown in Table 4-7 in Exhibit 4, Tab 2, Schedule 8 included in the amounts shown in Table 4-1 in Exhibit 4, tab 1, Schedule 1?

Answer: No, only recoverable expense are shown in Table 4-1

b) Are the non-recoverable amounts shown in Table 4-7 in Exhibit 4, Tab 2, Schedule 8 included in the amounts shown in Table 4-3 in Exhibit 4, Tab 1, Schedule 2?

Answer: No, only recoverable expense are shown in Table 4-3

c) Are the non-recoverable amounts shown in Table 4-7 in Exhibit 4, tab 2, Schedule 8 included in the amounts shown in Table 4-5 in Exhibit 4, Tab 1, Schedule 2?

Answer: No, only recoverable expense are shown in Table 4-5

4-Energy Probe-41

Ref: Exhibit 4, Tab 3, Schedule 1

a) The analysis of Information Technology expenses provided on pages 15 - 17 indicates that the increase in 2012 was due to a number of items. However, the table shows an increase of only $11,000 between 2011 and 2012. Please reconcile.

Answer: The table below shows the increase year over year for 2012 to 2011. Notably, in 2011 several Service Contract items were expensed that should have been expensed over the life of the agreement rather than fully expensed in 2011. Additionally, less labour was capitalized to Special Projects as they wrapped up (Smart Meters).

Labour	74,000
Purchasing & Warehouse Allocation	4,000
Professional Fees	13,000
Service Contracts - Hardware	(22,000)
Service Contracts - Software	(89,000)
Disaster Recovery	15,000
OEB Clearing Accounts	16,000
Net Increase	11,000

b) The increase in information technology costs shown in table are $266,724 in 2013 and $267,700 in 2014. The explanations provided on page 16 account for only a fraction of these increases. Please provide a more detail breakdown of the increases in 2013 and 2014 and show the associated dollars with each of the reasons provided on page 16.

Answer: See interrogatory 4-Staff-24

4-Energy Probe-42

Ref: Exhibit 4, Tab 7, Schedule 1

The evidence indicates that KWHI has used the half year methodology for both pooled and identifiable assets for the 2014 test year.

a) How has the depreciation been calculated for each of these two types of assets in 2009 through 2013? Did KWHI make any changes during this period?

Answer: KWHI calculates a full year of depreciation in the year of acquisition on its pooled assets and uses purchase month as the beginning date for calculation of depreciation for its identifiable assets. This has been consistently applied for all years except for the 2014 Test Year for which the half year rule has been applied. The only changes made during this period relate to revised service lives for the purposes of modified CGAAP.

b) How was the depreciation calculated as part of the cost of service application for 2010 rates? Have any changes in the methodology or rates used in that filing been made through to 2013 other than the change in rates in 2012 when KWHI moved to modified CGAAP?

Answer: KWHI used the same methodology for its final 2010 rate application as described above. There have been no other changes except those relating to modified CGAAP.

4-Energy Probe-43

Ref: Exhibit 4, Tab 7, Schedule 1 &
Exhibit 2, Tab 3, Schedule 3 & RRWF

Please reconcile the 2014 depreciation expense of $8,205,852 shown in Table 4-21 in Exhibit 4, Tab 7, Schedule 1 and the resulting net depreciation expense of $6,077,500 shown in Appendix 2-B for 2014 in Exhibit 2, Tab 3, Schedule 3, Attachment 1 (after adjustments for account 1576 and transportation) to the figure of $6,164,947 shown in the RRWF. What is the difference of approximately $87,000 related to?

Answer: The RRWF that was filed on June 21 shows $6,077,500 for Depreciation, the same as Appendix 2-B in Exhibit 2, Tab 3, Schedule 3, Attachment 1 (after adjustments for account 1576 and transportation). There is no difference of $87,000.

The RRWF that was filed on August 9th shows the Depreciation as $7,562,852 which is $1,485,353 higher than June 21st depreciation number and is explained as the depreciation on account 1576.

4-Energy Probe-44

Ref: Exhibit 4, Tab 7, Schedule 1 & Exhibit 2, Tab 3, Schedule 3

The above referenced exhibits indicate that $643,000 in transportation equipment depreciation has been allocated to capital and OM&A in 2014.

a) Please indicate the amount allocated to capital and the amount allocated to OM&A in 2014.

Answer: Approximately $378,000 will be OM&A and the remainder will be capitalized. This is based on a historical split of capital versus OM&A expenses. The majority of vehicle depreciation ($578,000) is burdened, and the historical split for vehicle overhead is 46% capital 54% operating and maintenance.

b) Is the amount allocated to OM&A in 2014 included in the total OM&A expenses for the test year of $18,523,200 as shown in Table 4-1 or is this amount in addition to the amount shown in Table 4-1?

Answer: The OM&A in 2014 on Table 4-1 includes the depreciation of vehicles.

4-Energy Probe-45

Ref: Exhibit 4, Tab 8, Schedule 1

a) Please explain the addition of $1,000 to taxable income in 2014 shown in Table 4-37. Is this related to recoverable or non-recoverable expenses?

Answer: The $1,000 addition to taxable income in 2014 was for donations; however, there was an error in the spreadsheet. It is deducted correctly; however, in the revenue requirement model as shown below:

Determination of Tax Adjustments to Accounting Income for 2014

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Amortization of tangible assets	104	8,205,853	0	8,205,853
Loss on disposal of assets	111	0	0	0
Non-deductible meals and entertainment expense	121	22,000	0	22,000
Federal Apprenticeship 2013		4,000	0	4,000
Other Additions - Ontario Apprentice & Co-op Education Tax Credits	295	56,000	0	56,000
Total Additions		**8,287,853**	**0**	**8,287,853**
Deductions:				
Gain on disposal of assets per financial statements	401	30,000	0	30,000
Capital cost allowance from Schedule 8	403	14,218,775	0	14,218,775
Total Deductions		**14,248,775**	**0**	**14,248,775**
Charitable donations from Schedule 2	311	1,000	0	1,000
Total Adjustments		**1,000**	**0**	**1,000**
Tax Adjustments to Accounting Income		**(5,959,922.41)**	**0.0**	**(5,959,922.41)**

b) Please indicate what is included in the $60,000 for Other Additions in 2014 in Table 4-37.

Answer: The $60,000 added to net income in 2014 pertain to tax credits that must be added back on to booked income as the tax credits are subject to income tax and KWHI must pay PILS on. The $60,000 is comprised of the following tax credits:

Co-operative education tax credit	**$ 6,000**
Apprenticeship tax credit (provincial)	**$50,000**
Apprenticeship tax credit (federal)	**$ 4,000**

c) Please provide a breakdown of the $95,000 in Miscellaneous Deductions shown in Table 4-37 for 2014.

Answer: See below:

Small Business Deduction	35,000
Co-operative Education Credit	6,000
ATTC (Provincial)	50,000
ATTC (Federal)	4,000
Total Tax Credits	95,000

4-Energy Probe-46

Ref: Exhibit 4, Tab 8, Schedule 1 &
Exhibit 4, Tab 4, Schedule 1

a) Please reconcile the 2 co-op students noted on page 4 of Exhibit 4, Tab 8, Schedule 1 with the figures provided at page 4 of Exhibit 4, Tab 4, Schedule 1.

Answer: As noted in Exhibit 4, Tab 8, Schedule 1 (page 4), the number of co-op students fluctuates year over year but has never been *less* than two. KWHI therefore conservatively estimated two co-op students for 2014 in its original forecast. Note that KWHI does hire summer students; however, they do not qualify as co-op students.

Now that it is Q4, KWHI can more accurately estimate that it will employ 8 co-op students in 2013. This includes 4 co-op PLT's and 4 clerical.

For 2014 and forward, KWHI would now estimate 6 co-op students to be employed, including 4 co-op PLT's and 2 clerical.

b) Please reconcile the 2 apprentices that qualify for the Federal Apprenticeship Tax Credit as noted on page 4 of Exhibit 4, Tab 8, Schedule 1, with the figures provided at pages 2-3 of Exhibit 4, Tab 4, Schedule 1. In particular, since the federal credit is available for the first two years of the program, has KWHI taken into account the apprentices hired part way through 2012, those hired in 2013 and those forecast to be hired in 2014?

Answer: KWHI did take the differing lengths of the apprenticeship tax credits into account when forecasting the tax credits. It should be noted that the first (2) and second year (2) PLT apprentices noted in Exhibit 4, Table 4, Schedule 1 are, at present, co-op students and not apprentices per se. There is no guarantee that they will be hired on at the end of their schooling by KWHI.

In addition, KWHI does expect to add new apprentices over the next rebasing period but hopes to hire more senior apprentices which would not necessarily qualify for tax credits. There is a concern that too many junior apprentices would create safety concerns.

c) Please reconcile the three Apprentice Powerline Technicians noted on page 2 of Exhibit 2, Tab 4, Schedule 1 with the statement on the following page that two additional Powerline Technicians are planned for the 2013 bridge year and two more in 2014.

Answer: As with the co-op students, KWHI can now update these figures with actuals. It notes that it has hired 3 apprentices in 2013. Two will qualify for both the federal and provincial apprenticeship tax credits in 2013; however, they will not qualify for the federal tax credit in 2014. One will qualify for the provincial apprenticeship tax credit only. Further, only one of the apprentices claimed in 2012 will qualify for the provincial tax credit in 2013

KWHI further estimates that it will hire two additional apprentices in 2014 which would qualify for the federal and provincial apprenticeship tax credits.

d) Please reconcile the 5 apprentices that qualify for the Ontario Apprenticeship Tax Credit in 2014 (page 4 of Exhibit 4, Tab 8, Schedule 1) with the numbers of apprentices shown at pages 2-3 of Exhibit 4, Tab 4, Schedule 1. In particular, since the provincial credit is available for the first four years of the apprenticeship, has KWHI taken into account the apprentices hired part way through 2010, along with those hired in 2011, 2012 and forecast to be hired in 2013 and 2014?

Answer: See answer above.

e) Please reconcile the $6,000 in Ontario Co-op Education Tax Credits based on 2 co-op students noted on page 4 of Exhibit 4, Tab 8, Schedule 1 with number of 3 co-ops shown in Table 4-39 for 2014.

Answer: The numbers can no longer be reconciled as the estimated hires have changed.

f) What is the impact on the 2014 taxable income of the Schedule One Adjustment noted on pages 7 and 8 of Exhibit 4, Tab 8, Schedule 1?

Answer: The adjusted co-op and apprentices hired have been adjusted in the table below:

Apprentices

	2009	2010	2011	2012	2013	2014
Federal # of Apprentices	4	6	4	2	2	2
Federal Tax Credit	6,280	12,000	8,000	2,730	4,000	4,000
Provincial # of Apprentices	5	7	7	4	4	2
Provincial Tax Credit	44,175	70,000	52,931	10,382	40,000	20,000

Co-ops

	2009	2010	2011	2012	2013	2014
# of Co-ops	5	3	9	2	8	6
Provincial Tax Credit	44,175	8,223	23,059	4,318	24,000	18,000

The adjusted tax credits are shown below:

2013 PILs Schedule

Description	Source or Input	Tax Payable
Accounting Income	10' Rev Def	4,451,863
Tax Adj to Accounting Income	10' Rev Def	(5,722,893)
Taxable Income		**(1,271,030)**
Combined Income Tax Rate	PILs Rates	26.500%
Total Income Taxes		**-**
Small Business Deduction		35,000
Co-operative Education Credit		24,000
ATTC (Provincial)		40,000
ATTC (Federal)		4,000
Total Tax Credits		103,000
Total PILs		**-**

2014 PILs Schedule

Description	Source or Input	Tax Payable
Accounting Income	10' Rev Def	7,943,157
Tax Adj to Accounting Income	10' Rev Def	(6,217,240)
Taxable Income		**1,725,916**
Combined Income Tax Rate	PILs Rates	26.500%
Total Income Taxes		**457,368**
Small Business Deduction		35,000
Co-operative Education Credit		18,000
ATTC (Provincial)		20,000
ATTC (Federal)		4,000
Total Tax Credits		77,000
Total PILs		**380,368**

The impact on the revenue sufficiency is that is has decreased by $18,000 from $793,268 to $775,268. See table below:

Revenue Sufficiency/Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test Required Revenue
Revenue:			
Revenue Deficiency			**(775,268)**
Distribution Revenue	38,163,923	38,207,936	38,207,936
Other Operating Revenue (Net)	1,840,800	2,039,200	2,039,200
Accounting Changes Under CGAAP - Account 1576	(3,676,200)		
Total Revenue	**36,328,523**	**40,247,136**	**39,471,868**
Costs and Expenses:			
Administrative & General, Billing & Collecting	6,805,075	7,261,800	7,261,800
Operation & Maintenance	10,626,000	11,261,400	11,261,400
Depreciation & Amortization	7,169,353	7,562,853	7,562,853
Property Taxes	376,000	394,800	394,800
Capital Taxes			
Deemed Interest	6,801,351	5,019,405	5,019,405
Total Costs and Expenses	**31,777,778**	**31,500,258**	**31,500,258**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**31,777,778**	**31,500,258**	**31,500,258**
Utility Income Before Income Taxes	**4,550,744**	**8,746,879**	**7,971,610**
Income Taxes:			
Corporate Income Taxes		656,773	451,327
Total Income Taxes		**656,773**	**451,327**
Utility Net Income	**4,550,744**	**8,090,105**	**7,520,283**
Capital Tax Expense Calculation:			
Total Rate Base	201,820,490	209,362,001	209,362,001
Income Tax Expense Calculation:			
Accounting Income	4,550,744	8,746,879	7,971,610
Tax Adjustments to Accounting Income	(5,684,371)	(5,977,922)	(5,977,922)
Taxable Income	**(1,133,627)**	**2,768,956**	**1,993,688**
Income Tax Expense before deductions		733,773	528,327
Miscellaneous Deductions		(77,000)	(77,000)
Income Tax Expense after deductions		656,773	451,327

4-Energy Probe-47

Ref: Exhibit 4, Tab 8, Schedule 1

a) Please explain why KWHI has included capital expenditures on computer software in CCA Class 50, rather than in CCA Class 12 in both 2013 and 2014 as shown in Tables 4-43 and 4-44 in Exhibit 4, Tab 8, Schedule 1, despite the continuity statements for these years shown in Appendix 2-B in Exhibit 2, Tab 3, Schedule 3, Attachment 1 indicating that the computer software expenditures are in CCA Class 12.

Answer: All software purchased by KWHI has been added to CCA class 50, not CCA class 12. KWHI, in its PILS filings, has considered software packages such as Microsoft Office to be

applications software. These software packages are not typically within the capitalization threshold and have not been recognized as capital additions. These are the software packages that KWHI would typically classify as CCA class 12. All other software purchased/developed is considered to be system software and applicable to CCA class 50.

The field in Appendix 2-B was not updated in the model used by KWHI for the purposes of the fixed asset continuity schedule.

b) Please provide revised Tables 4-43 and 4-44 with the computer software additions added to CCA Class 12 rather than Class 50.

Answer: See Below

Table 4-43 Revised

CCA Continuity Schedule (2013)

Class	Class Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to Feb 22/05	99,253,028			99,253,028	0	99,253,028	4%	3,970,121	95,282,907
1b		4,020,357	500,000		4,520,357	250,000	4,270,357	6%	256,221	4,264,136
2	Distribution System - pre 1988	8,473,139			8,473,139	0	8,473,139	6%	508,388	7,964,751
3	Buildings - pre 1988	2,733,152			2,733,152	0	2,733,152	5%	136,658	2,596,494
8	General Office/Stores Equipment	7,504,409	905,000		8,409,409	452,500	7,956,909	20%	1,591,382	6,818,027
10	Vehicles	1,752,918	1,124,200	80,000	2,797,118	522,100	2,275,018	30%	682,505	2,114,613
12	Computer Software	0	341,000	0	341,000	0	341,000	100%	341,000	0
17	New Electrical Generating Equipment - Feb 27/00 Other Than Bldgs	391,201			391,201	0	391,201	8%	31,296	359,905
45.1	Computers & Systems Hardware - post Mar 19/07	21,386			21,386	0	21,386	45%	9,624	11,762
46	Data Network Infrastructure Equipment - post Mar 22/04	59,451			59,451	0	59,451	30%	17,835	41,616
47	Distribution System - post Feb 22/05	62,361,410	19,002,400		81,363,810	9,501,200	71,862,610	8%	5,749,009	75,614,801
50	Computer equipment - post January 27, 2009	592,065	398,000		990,065	199,000	791,065	55%	435,086	554,979
	SUB-TOTAL - UCC	**187,162,516**	**22,270,600**	**80,000**	**209,353,116**	**10,924,800**	**198,428,316**		**13,729,125**	**195,623,990**

Table 4-44 Revised

CCA Continuity Schedule (2014)

Class	Class Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to Feb 22/05	95,282,907			95,282,907	0	95,282,907	4%	3,811,316	91,471,591
1b		4,264,136	161,200		4,425,336	80,600	4,344,736	6%	260,684	4,164,652
2	Distribution System - pre 1988	7,964,751			7,964,751	0	7,964,751	6%	477,885	7,486,866
3	Buildings - pre 1988	2,596,494			2,596,494	0	2,596,494	5%	129,825	2,466,669
8	General Office/Stores Equip	6,818,027	772,000		7,590,027	386,000	7,204,027	20%	1,440,805	6,149,222
10	Vehicles	2,114,613	920,000	80,000	2,954,613	420,000	2,534,613	30%	760,384	2,194,229
12	Computer Software	0	360,000	0	360,000	0	360,000	100%	360,000	0
17	New Electrical Generating Equipment - Feb 27/00 Other Than Bldgs	359,905			359,905	0	359,905	8%	28,792	331,113
45.1	Computers & Systems Hardware acq'd post Mar 19/07	11,762			11,762	0	11,762	45%	5,293	6,469
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	41,616			41,616	0	41,616	30%	12,485	29,131
47	Distribution System - post 22-Feb-2005	75,614,801	15,072,731		90,687,532	7,536,366	83,151,167	8%	6,652,093	84,035,439
50	Computer equipment - post January 27, 2009	554,979	360,000		914,979	180,000	734,979	55%	404,239	510,741
	SUB-TOTAL - UCC	195,623,990	17,645,931	80,000	213,189,921	8,602,966	204,586,956		14,343,801	198,846,120

c) What is the impact on the 2014 CCA deduction and the PILs payable for 2014 of this change?

Answer: CCA deductions would increase by $247,225 in 2013 and $125,026 in 2014 if CCA class 12 was used for computer software rather than CCA class 50.

The effect on PILS payable is a decrease of $45,077 from $433,327 to $388,250.

4-Energy Probe-48

Ref: Exhibit 4, Tab 8, Schedule 1, &
RRWF &
Exhibit 4, Tab 8, Schedule 3

Page 1 of Exhibit 4, Tab 8, Schedule 3 indicates that the PILs amount calculated using the OEB's Income Tax/PILs workform is $433,327. However, the actual workform shows a calculated amount of $420,495. This difference is discussed on page 11 of Exhibit 4, Tab 8, Schedule 1. However, the grossed up income taxes shown in the RRWF is $429,466. Please reconcile this figure to the two previous figures.

Answer: The amount of grossed up PILS from the most recently filed RRWF (August 9, 2013) is $433,327 which corresponds to the most recent revenue requirement model filed for this application.

4-Energy Probe-49

Ref: Exhibit 4, Tab 8, Schedule 2 &
Exhibit 4, Tab 4, Schedule 1

The Ontario Apprenticeship Training Tax Credit shown in the 2012 filed tax return in Attachment 1 of Exhibit 4, Tab 8, Schedule 2 shows the calculation of the credits for four individuals hired in 2012.

a) Please confirm that these four individuals hired in 2012 are the same four Powerline Technicians noted on page 2 of Exhibit 4, Tab 4, Schedule 1 as being hired in 2012.

Answer: Confirmed

b) Why was there no Ontario Apprenticeship Training Tax Credit claimed associated with the two Powerline Technicians hired in 2010 or the four hired in 2011?

Answer: The apprentices hired in 2010 and 2011 did not start their apprenticeships with KWHI and were registered apprentices with other companies prior to coming to KWHI's employ. Since the Ontario Apprenticeship Training Tax Credit only applies to the first 48-month period of an apprenticeship (after March 26, 2009), KWHI assumes that the previous employer claimed their times of employ with them and did not claim the apprenticeship credits any longer after 2011.

b) Do any of the other apprentice positions shown in Exhibit 4, Tab 4, Schedule 1 qualify for the Ontario Apprenticeship Training Tax Credit (Meter Technician, P&C Technician, Station Operator Trainee, Engineering Technicians)?

Answer: No, they do not. KWHI consulted with KPMG for tax assistance and were informed that the only positions that it has that would qualify for the Ontario Apprenticeship Training Tax Credit would be the Powerline Technicians.

End of Energy Probe Exhibit Four Interrogatories

School Energy Coalition Exhibit Four Interrogatories

4-SEC-5

[Ex. 4/3/1 p.14]

Please provide any cost-benefit analysis or other documentation showing the operating cost impacts of the Service Centre renovation.

Answer: KWHI did not conduct a cost-benefit analysis on the operating cost impacts of the Service Centre renovation. The existing service centre building was built in 1987 and required updating to accommodate the needs of current and future staff and equipment. Washrooms and locker rooms were expanded and updated and the service garage was expanded to accommodate 12 new parking spaces for large size trucks and equipment. The 47, 000 ft^2 Service Centre building was expanded by 16, 443 ft^2 and the total area of renovation was 14, 168 ft^2.

4-SEC-6

[Ex. 4/4/1 p.8]

Please provide whatever documents are relied on for the statement “KWHI’s pay rates are competitive with other LDCs in the Waterloo Region”.

Answer: Attached as Appendix D.

4-SEC-7

[Ex. 4/5/1 p. 1]

Please advise what components of the work being done for the City and the Township will continue to be actually performed by the Applicant's employees. Please advise the basis on which the Applicant will bill KESI for this work, and explain any differences between the current charges to the City and the Township, and the expected charges to KESI.

Answer: It is expected that KWHI's staff will perform the work, being sub-contracted by KESI. KWHI expects that it will bill KESI on a monthly basis at full cost plus a mark-up on the total. KWHI does not currently charge a rate of return on the work performed for streetlighting activities.

4-SEC-8

[Ex. 4/7/1 p.3]

Please explain why there is such a substantial drop in Contributions and Grants upon conversion to IFRS.

Answer: Table 4-21 is not the Contributions and Grants but the Depreciation rate on Contribution and Grants. As the Depreciation expense has lowered due to extending the life of the assets, so too does the amortization expense lower on Contributions and Grants. The Useful life of the Contributions and Grants matches the related asset, therefore the amortization expense has gone down.

End of School Energy Coalition Exhibit Four Interrogatories

VECC Exhibit Four Interrogatories

4.0 - VECC- 20

Reference: Appendix 2-K KW Revised Filing Requirement or Exhibit 4, Tab 4, Schedule 1, Attachment 2 of 2

a) Please provide the month ending August 31 total salary and wages and (separately) the project year-end payments.

Answer: As at August 31, 2013 total salary and wages paid is $9,954,952

Projected salaries and wages to year end are estimated to be $4,845,138. Total estimated for 2013 $ 14,800,090

b) Please show the difference in 2012 MCGAAP and CGAAP for capitalized compensation (i.e. restate 2012 total compensation capitalized under CGAAP).

Answer: Note that the direct labour amount does not change regardless of whether MCGAAP or CGAAP is applied. Also note that the amounts below are based on changes to overhead factors and KWHI considers them to be reasonable proxies. The reallocation of management salaries pertains to senior staff salaries previously burdened and partially capitalized under pre-2012 CGAAP. Based on the 50/50 split of outside direct labour dollars for 2012, KWHI has estimated a reduction in capitalization of those salaries as specified below.

Labour Component	Modified CGAAP	Pre-2012 CGAAP	Variance
Direct labour	2,537,759	2,537,759	-
Supervisory Labour	96,626	96,626	-
Labour O/H	1,364,057	1,612,068	(248,010)
Supervisory Labour O/H	18,790	18,790	-
Engineering	1,272,475	1,798,199	(525,724)
Purchasing/Warehousing	302,884	503,302	(200,419)
Reallocation of Mgmt Salaries	-	116,919	(116,919)
Totals	***5,592,591***	***6,683,663***	***(1,091,072)***

4.0 - VECC- 21

Reference: Exhibit 4, Tab 1, Schedule 2 – 2010 comparisons

a) Please provide a breakdown comparison (major elements) of account 5655 – Regulatory Expense for 2010 vs. 2014.

Answer: See table below:

	2010 Actual	2011 Actual	2012 Actual	2013 Forecast	2014 Test
Labour	205,023	179,289	250,840	296,600	318,900
Office Expenses	8,176	20,629	13,698	17,800	18,300
IT Expenses	18,088	18,231	18,007	21,800	25,500
OEB Fees & Assessments	220,546	222,635	233,404	263,477	267,075
Rebasing Costs	40,523	40,523	40,523	40,523	68,125
	492,357	481,307	556,472	640,200	697,900

b) Please provide a breakdown comparison of account 5315 – Customer Billing for 2010 vs. 2014.

Answer: See table below:

	2010 Actual	2011 Actual	2012 Actual	2013 Forecast	2014 Test
Labour	719,381	759,857	801,496	860,100	912,100
IT Expenses	144,229	136,604	116,853	141,300	165,800
Office Expenses	24,981	24,256	32,515	44,100	45,700
Office Supplies	47,866	39,619	40,183	78,000	112,000
Postage	269,850	312,372	284,381	420,000	550,000
Advertising	30,752	37,843	26,603	50,000	45,000
EBT	(42,012)	(53,323)	(56,470)	(53,900)	(55,800)
Other	9,572	10,850	13,987	12,200	12,100
Smart Meters/Decision	(1,500)	(65,660)	91,285		
	1,203,119	1,202,418	1,350,832	1,551,800	1,786,900

c) Please provide a breakdown comparison of account 5310 – Meter Reading Expense for 2010 vs. 2014.

Answer: See table below:

	2010 Actual	2011 Actual	2012 Actual	2013 Forecast	2014 Test
Labour	75,400	155,103	130,107	77,700	72,800
IT Expenses	27,013	36,462	36,014	43,500	51,100
Office Expenses	11,610	10,384	15,362	17,900	18,200
Service Contracts (Sensus)	114,608	106,750	101,773	192,000	200,000
Vehicle	19,343	19,244	9,441	16,800	18,300
C&I Interval Interrogation	21,185	40,426	73,933	109,500	135,000
Other	4,382	5,464	15,059	7,200	7,000
Meter Reading (Olameter)	200,786	72,025	75,037	65,000	10,000
Smart Meters/Decision	(100,816)	(83,833)	344,208	-	-
	373,511	362,024	800,933	529,600	512,400

4.0 - VECC- 22

Reference: Exhibit 4, Tab 2, Schedule 5

a) Please provide the calculation which shows the derivation of the proposed $46,000 in LEAP funding for 2014.

Answer: As per table 6-7 in Exhibit 6 the distribution revenue required is $38,207,936. This is multiplied by 0.12% (from EB-2008-0150) and rounded up to give a figure of $46,000.

4.0 - VECC- 23

Reference: Exhibit 4, Tab 1

a) Please provide association fees paid to the EDA for each of the years 2010 through 2014 (forecast).

Answer:

KWHI has paid the following EDA fees:

2010	**63,720**
2011	**64,700**
2012	**68,200**
2013	**71,500**
Estimate 2014	**75,100**

b) Separately provide and describe the cost of all other association memberships.

Answer: KWHI also has a membership with the Kitchener Chamber of Commerce (2011, 2012 & 2013) for $2,090 annually. This membership extends KWHI's customer engagement opportunities through the power of referrals and networking.

KWHI is a member of the MEARIE Group, with a membership for HR Information Services (2011, 2012 & 2013) for $1,030 annually. This membership provides access to HR job postings, staff training and seminars.

KWHI had a membership (2010, 2011 & 2012) with MEARIE for Employee and Labour Relations Services for $14,000 annually. This membership provided HR services and Labour Relations accessible to KWHI's staff in place of a full KWHI HR Specialist. This membership was discontinued in 2013, when it was determined that KWHI's full time HR Specialist, hired mid-2012 would be able to perform the duties previously supplied by the MEARIE membership. The decision to cancel the membership for 2013 was made in 2013, which was after the 2013 budget had been approved in 2012.

4.0 - VECC- 24

Reference: Exhibit 4, Tab 1, Schedule 1, pg.1

a) KWHI notes that 2012 expenses were increased by $1.6m due the adoption of MCGAP. Please provide a breakdown showing the element sources of this increase.

Answer: See the table below. Note the two subtotals ($832,418 and $859,921) equal the $1.692 million.

OM&A Adjustments

	GAAP (post-2011)	GAAP (Pre-2012)	Variance
Net Income	9,182,770	9,269,713	86,942
Changes to Net Income	**GAAP (new)**	**GAAP (old)**	**Variance**
Direct labour-related burdens	(1,361,482)	1,608,783	(247,301)
Plant & material overheads	(959,855)	1,565,324	(605,469)
Miscellaneous overheads	(3,555,552)	1,870,364	1,685,188
Subtotal Burdens	*(5,876,889)*	*5,044,472*	***832,418***
Reallocation of Trucks to Operations	-	-	-
Reallocation of Engineering	(626,084)	-	626,084
Reallocation of Wages to Expense	-	(233,837)	233,837
Subtotal Reallocations	*(626,084)*	*(233,837)*	***859,921***
Amortization	-	3,870,609	(3,870,609)
	(6,502,973)	8,681,244	(2,178,271)
Variance is account 1576			**2,265,213**

b) At the same reference it notes that 2012 expenses increased by $1.1m due to the Smart Meter Cost Recovery Decision. Please explain the element sources (i.e. components) of this increase. Is this amount a one-time cost or a recurring incremental part of OM&A?

Answer: The one-time costs are items like printing, mailing, advertising, installation labour and legal fees. The recurring items are ODS fees, meter reading fees, security audits, and software license fees. See below for a breakdown of the one-time costs versus the ongoing costs.

One-Time Costs

	2009	2010	2011	Apr-12	Subtotal	Dec-12	Total
Operations	55,514	45,180	89,270	30,380	220,345	-	220,345
Billing & Collecting	24,318	1,527	74,528	-	100,374	-	100,374
Admin	13,333	9,106	2,731	-	25,170	-	25,170
	93,165	55,813	166,530	30,380	345,888	-	345,888

Recurring Costs

	2009	2010	2011	Apr-12	Subtotal	Dec-12	Total
Operations	-	5,805	155,958	270,983	432,746	(143,353)	289,393
Billing & Collecting	69,466	100,806	84,431	24,647	279,349	143,353	422,702
Admin	-	-	-	26,479	26,479	-	26,479
	69,466	106,611	240,389	322,109	738,575	-	738,575
	162,631	**162,424**	**406,919**	**352,490**	**1,084,463**		**1,084,463**

4.0 - VECC- 25

Reference: Exhibit 4, Tab 3, Schedule 1, pg. 16

a) Please provide the forecast software maintenance costs for the Outage Management System.

Answer: Software Maintenance costs for the Outage Management System are forecast to be $80,000 in 2014.

4.0 - VECC- 26

Reference: Exhibit 4, Tab 4, Schedule 1,pg. 10 / Attachment 2

a) Please reconcile the Benefits shown at Exhibit 4, Tab 4, Schedule 1 with the Total Benefits shown at Appendix 2-K.

Answer: The benefits shown on page E4 T4 S1 page 10 do not include OMERS, CPP, EI, EHT or WSIB. The above table show the total of the Employee Benefits, Sun Life and Long Term disability that matches the total on E4 T4 S1 page 10 and adds the other benefits to get to the totals on Appendix 2-K.

See table below:

	Actual 2010	Actual 2011	Actual 2012	Bridge 2013	Test 2014
Employee Benefits	687,208	682,713	691,517	760,700	783,600
Sun Life	44,345	52,830	53,016	62,400	64,300
Long Term Disability	157,589	167,505	174,055	185,000	190,500
Sub Total (As per Table 4-15 E4T3S1 pg 10)	**889,141**	**903,048**	**918,588**	**1,008,100**	**1,038,400**
OMERS	868,303	953,638	1,142,919	1,353,187	1,448,433
CPP	379,245	383,928	393,074	409,706	417,979
EI	164,638	172,869	182,344	196,283	209,172
EHT	256,008	254,477	256,922	265,543	272,092
WSIB	113,832	111,409	120,279	138,141	142,071
	1,782,026	**1,876,321**	**2,095,538**	**2,362,860**	**2,489,746**
	2,671,167	**2,779,370**	**3,014,126**	**3,370,960**	**3,528,146**
Accrued Pension benefits	198,003	241,188	235,026	225,578	253,418
Total (As per Appendix 2-K)	**2,869,170**	**3,020,558**	**3,249,152**	**3,596,538**	**3,781,564**

b) Please explain the increase shown in Board Approved 2010 Benefits (943k) as compared to 2010 Actuals (2,671k).

Answer: The 2010 Board Approved Benefits Includes only Employee Health Benefits including Life Insurance and LTD costs. The 2010 Actuals also includes OMERS, CPP, EI EHT, WSIB and Accrued Pension and Post-Retirement Benefits.

4.0 – VECC – 27

Reference: Exhibit 1, Tab 1, Schedule 19

Preamble: *The street lighting services have been provided by KWHI in the past but are expected to be moved to an affiliate of KWHI, Kitchener Energy Services Inc. (KESI) by mid-2013. KESI is currently in the process of completing service agreements with the City of Kitchener with the other parties to follow. Once the service agreements are final, KWHI will outsource this activity to KESI using a cost recovery basis plus a rate of return.* (Page 1 of 1).

a) The evidence implies that after the service agreement KESI will contract with KWHI to serve the City of Kitchener. Please confirm this correct interpretation of the above statement.

Answer: KESI will contract with the City of Kitchener, not with KWHI. It is expected that KWHI's staff will perform the work, being sub-contracted by KESI.

b) If so, please explain why KESI is not contracting directly with the City of Kitchener. In your response please detail what if any relationship is expected between KWHI and KESI in 2014.

Answer: KESI will be contracting with the City of Kitchener, not with KWHI. In 2014, KWHI will continue to be affiliated with KESI. See part a) above.

4.0 - VECC- 28

Reference: Exhibit 4, Tab 5, Schedule 1, Table 4-19

a) Do the items marked "Revenue" in Table 4-19 represent the costs incurred by KWHI for streetlight related activity made on behalf of the municipalities?

Answer: Yes

4.0-VECC – 29

Reference: Exhibit 4, Tab 6, Schedule 1, Attachment 1 of 1

Preamble: KWHI's Procurement Policy reads in part: "*Where the estimated value of goods or services required exceeds $100,000 the purchase shall be made by a request for sealed tenders*".

a) KWHI's Non-Affiliated Vendors list shows a number of purchases which exceed the $100k value, but which appear not to have been tendered (i.e. subject to quote). Please explain this apparent discrepancy.

Answer: Some purchases are, in aggregate, higher than $100K. For vendors that supply many orders during the year, quotes are obtained from three vendors at an order level. This vendor may supply more than $100K during the year, but not enough at one time that a tender would be required.

Some vendors build supplies specifically for KWHI. These vendors build and hold supply for KWHI and may be unique vendors to KWHI. Periodically, other vendors are contacted to ensure that the price that is being paid is competitive to other vendors that may be willing to build and carry supply for KWHI.

From KWHI Purchasing Policy (Page 3 of 6)

"Where the value of goods or services required is in excess of $20,000 but does not exceed $100,000, the purchase may be made on the authority of the Purchasing Manager provided a requisition signed by the Department Head or designate, the Vice President, and President, has been obtained and an attempt has been made to obtain three (3) written formal quotations, unless the goods or services are non-competitive"
Some purchases – such as Smart Meters – were purchased from specified vendors based on a pre-approved process.

b) Was the Mearie Group insurance purchase subject to a competitive process? If yes, please explain the process. If not, please explain why not and what steps were taken to ensure that the insurance package purchased was competitive with other offerings.

Answer: No. KWHI has placed its insurance with MEARIE since 1987. MEARIE is a Reciprocal Insurance Exchange whose members are comprised of the Local Distribution Companies ("LDCs") and MEARIE's Board of Directors is comprised of representatives from LDCs including representation from KWHI. As a Reciprocal Insurance Exchange, MEARIE is a not for profit organization whose objective is to provide LDCs broad and cost effective insurance coverage specifically designed for the LDC industry. Since inception, MEARIE subscribers, including KWHI, have benefited from over $14M in premium reductions. MEARIE's insurance policy is tailored for LDC's and includes coverages such as Environmental, Terrorism, Directors & Officers and Privacy & Cyber Breach coverages all under one policy which is not available with other offerings. MEARIE's Board of Directors establishes the rates charged for insurance based upon actuarial analysis of what is needed to fund only claims and expenses and not any profit (unlike traditional insurance market offerings).

4.0-VECC – 30

Reference: Exhibit 4, Tab 7, Schedule 1

a) What would be the 2014 revenue requirement adjustment if all the useful lives of assets chosen by KWHI were compliant with the Kinectrics recommendations (i.e. elimination of variations shown in Table 4-24 through 4-33)?

Answer: In order to properly answer this question, it would take several weeks to calculate the actual results. The reasons for this include:

- **breaking down the costs into other categories (ie 50 versus 45 years) would take quite a length of time to research**
- **determining the remaining useful life for each asset would take days**
- **Depreciation would need to be calculated every year since 2012 to determine the effect on rate base**

However, in order to be helpful to the process, KWHI has estimated a ballpark for this.

		2012	2013	2014
	Original Depreciation	10,119,991	7,705,054	8,205,853
	Estimated Depreciation	11,305,704	8,205,179	8,833,577
As filed	Ending Asset Balance	163,614,013	178,179,560	187,667,038
Estimated	Ending Asset Balance	162,428,301	176,493,722	185,353,476

Based on the information above, if KWHI had used all depreciation rates compliant with the Kinectrics study, its revenue requirement would be $40,162,246 and its revenue sufficiency would decrease to $84,891.

Table 6-7

Revenue Sufficiency/Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test Required Revenue
Revenue:			
Revenue Deficiency			(84,891)
Distribution Revenue	38,163,923	38,207,936	38,207,936
Other Operating Revenue (Net)	1,840,800	2,039,200	2,039,200
Accounting Changes Under CGAAP - Account 1576	(3,676,200)		
Total Revenue	**36,328,523**	**40,247,136**	**40,162,246**
Costs and Expenses:			
Administrative & General, Billing & Collecting	6,805,075	7,261,800	7,261,800
Operation & Maintenance	10,626,000	11,261,400	11,261,400
Depreciation & Amortization	7,669,479	8,190,577	8,190,577
Property Taxes	376,000	394,800	394,800
Capital Taxes			
Deemed Interest	6,752,965	4,971,463	4,971,463
Total Costs and Expenses	**32,229,519**	**32,080,040**	**32,080,040**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**32,229,519**	**32,080,040**	**32,080,040**
Utility Income Before Income Taxes	**4,099,004**	**8,167,097**	**8,082,206**
Income Taxes:			
Corporate Income Taxes		656,248	633,752
Total Income Taxes		**656,248**	**633,752**
Utility Net Income	**4,099,004**	**7,510,849**	**7,448,454**

4.0-VECC – 31

Reference: Exhibit 4, Tab 2, Schedule 8, Attachment 1 of 1

a) Please update Appendix 2-G 2013 column to show the OM&A spent to-date (month ending August) and, in a separate column the projected spending for the remainder of the year.

Answer: See below:

Appendix 2-G
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account Description	Last Rebasing Year (2010 Actuals)	2011 Actual	2012 Actual[2]	Bridge Year 2013[3] Actual to August 31	Bridge Year 2013[3] Projected to Year end	Bridge Year 2013[3]	Test Year 2014
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations							
5005 Operation Supervision and Engineering	$ 526,577	$ 758,696	$ 1,697,769	$ 1,272,203	$ 2,179,900	$ 2,256,200	$ 2,501,400
5010 Load Dispatching	$ 614,270	$ 591,453	$ 649,357	$ 481,242	$ 750,000	$ 676,500	$ 697,500
5012 Station Buildings and Fixtures Expense						$ -	
5014 Transformer Station Equipment - Operation Labour	$ 281,354	$ 273,646	$ 279,711	$ 199,736	$ 434,700	$ 285,100	$ 294,700
5015 Transformer Station Equipment - Operation Supplies and Expenses	$ 553,544	$ 529,505	$ 575,564	$ 418,554	$ 531,300	$ 628,600	$ 647,500
5016 Distribution Station Equipment - Operation Labour	$ 5,825	$ 4,842	$ 6,127	$ 4,513	$ 7,400	$ 5,500	$ 5,700
5017 Distribution Station Equipment - Operation Supplies and Expenses	$ 15,226	$ 13,536	$ 17,042	$ 15,028	$ 22,100	$ 16,700	$ 17,200
5020 Overhead Distribution Lines and Feeders - Operation Labour	$ 17,401	$ 16,071	$ 29,030	$ 36,658	$ 29,700	$ 24,000	$ 24,600
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 27,453	$ 23,869	$ 100,941	$ 92,397	$ 113,300	$ 91,400	$ 42,300
5030 Overhead Sub-transmission Feeders - Operation							
5035 Overhead Distribution Transformers - Operation							
5040 Underground Distribution Lines and Feeders - Operation Labour	$ 310,008	$ 340,327	$ 357,355	$ 261,088	$ 384,400	$ 400,300	$ 410,400
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 130,169	$ 145,477	$ 192,134	$ 149,743	$ 227,600	$ 237,000	$ 241,700
5050 Underground Sub-transmission Feeders - Operation							
5055 Underground Distribution Transformers - Operation							
5060 Street Lighting and Signal System Expense							
5065 Meter Expense	$ 285,880	$ 499,602	$ 868,071	$ 522,589	$ 776,000	$ 687,600	$ 699,700
5070 Customer Premises - Operation Labour	$ 10,878	$ 10,677	$ 5,601	$ 4,399	$ 6,600	$ 7,400	$ 7,600
5075 Customer Premises - Operation Materials and Expenses	$ 16,851	$ 13,664	$ 7,956	$ 7,533	$ 10,400	$ 11,800	$ 12,400
5085 Miscellaneous Distribution Expenses							
5090 Underground Distribution Lines and Feeders - Rental Paid	$ 9,405	$ 17,921	$ 15,208	$ 18,813	$ 20,000	$ 16,400	$ 17,300
5095 Overhead Distribution Lines and Feeders - Rental Paid	$ 19,879	$ 19,349	$ 19,443	$ 12,976	$ 25,500	$ 21,000	$ 22,000
5096 Other Rent							
Total - Operations	$ 2,824,720	$ 3,258,635	$ 4,821,308	$ 3,497,474	$ 5,518,900	$ 5,365,500	$ 5,642,000
Account Description	**Last Rebasing Year (2010 Actuals)**	**2011 Actual**	**2012 Actual[2]**	**Bridge Year 2013[3] Actual to August 31**	**Bridge Year 2013[3] Projected to Year end**	**Bridge Year 2013[3]**	**Test Year 2014**
Maintenance							
5105 Maintenance Supervision and Engineering							
5110 Maintenance of Buildings and Fixtures - Distribution Stations	$ 126,049	$ 149,303	$ 193,574	$ 140,154	$ 193,400	$ 201,600	$ 183,000
5112 Maintenance of Transformer Station Equipment	$ 264,109	$ 579,330	$ 685,771	$ 399,649	$ 656,200	$ 661,800	$ 748,100
5114 Maintenance of Distribution Station Equipment	$ 23,182	$ 58,337	$ 38,473	$ 41,279	$ 82,400	$ 124,100	$ 79,100
5120 Maintenance of Poles, Towers and Fixtures	$ 373,991	$ 443,347	$ 444,489	$ 202,366	$ 297,100	$ 294,600	$ 359,600
5125 Maintenance of Overhead Conductors and Devices	$ 697,692	$ 866,573	$ 893,395	$ 799,081	$ 1,262,600	$ 1,063,000	$ 1,089,500
5130 Maintenance of Overhead Services	$ 1,331,737	$ 1,384,653	$ 1,464,732	$ 1,153,098	$ 1,688,500	$ 1,561,500	$ 1,681,700
5135 Overhead Distribution Lines and Feeders - Right of Way							
5145 Maintenance of Underground Conduit	$ 336,884	$ 184,248	$ 250,540	$ 73,613	$ 109,800	$ 277,800	$ 302,100
5150 Maintenance of Underground Conductors and Devices	$ 250,976	$ 489,648	$ 587,888	$ 402,567	$ 453,800	$ 455,200	$ 473,800
5155 Maintenance of Underground Services	$ 231,388	$ 201,733	$ 245,749	$ 143,063	$ 229,000	$ 208,600	$ 217,700
5160 Maintenance of Line Transformers	$ 363,340	$ 471,370	$ 339,665	$ 190,967	$ 344,300	$ 411,700	$ 484,200
5165 Maintenance of Street Lighting and Signal Systems							
5170 Sentinel Lights - Labour							
5172 Sentinel Lights - Materials and Expenses							
5175 Maintenance of Meters	$ 70,262	$ 27,675	$ 82,478	$ 1,303	$ 1,300	$ 600	$ 600
5178 Customer Installations Expenses - Leased Property							
5195 Maintenance of Other Installations on Customer Premises							
Total - Maintenance	$ 4,069,611	$ 4,856,219	$ 5,226,753	$ 3,547,140	$ 5,318,400	$ 5,260,500	$ 5,619,400
Account Description	**Last Rebasing Year (2010 Actuals)**	**2011 Actual**	**2012 Actual[2]**	**Bridge Year 2013[3] Actual to August 31**	**Bridge Year 2013[3] Projected to Year end**	**Bridge Year 2013[3]**	**Test Year 2014**
Billing and Collecting							
5305 Supervision	$ 198,624	$ 237,871	$ 242,320	$ 131,155	$ 256,000	$ 256,000	$ 278,700
5310 Meter Reading Expense	$ 474,328	$ 437,507	$ 800,933	$ 195,359	$ 529,600	$ 529,600	$ 512,400
5315 Customer Billing	$ 1,324,913	$ 1,338,095	$ 1,414,088	$ 896,723	$ 1,492,800	$ 1,620,800	$ 1,857,200
5320 Collecting	$ 722,738	$ 772,098	$ 909,893	$ 629,427	$ 1,027,800	$ 1,063,800	$ 1,138,500
5325 Collecting - Cash Over and Short	$ 109	$ 103		$ 19	$ -		
5330 Collection Charges	$ 25,764	$ 28,531					
5335 Bad Debt Expense	-$ 46,363	$ 103,015	$ 146,917	$ 200,000	$ 187,000	$ 147,000	$ 147,000
5340 Miscellaneous Customer Accounts Expenses		$ 2,682					
Total - Billing and Collecting	$ 2,700,114	$ 2,919,902	$ 3,514,152	$ 2,052,684	$ 3,493,200	$ 3,617,200	$ 3,933,800

Appendix 2-G

Detailed, Account by Account, OM&A Expense Table

(excluding Depreciation and Amortization)

Account Description	Last Rebasing Year (2010 Actuals)	2011 Actual	2012 Actual[2]	Bridge Year 2013[3] Actual to August 31	Bridge Year 2013[3] Projected to Year end	Bridge Year 2013[3]	Test Year 2014
Community Relations							
5405 Supervision							
5410 Community Relations - Sundry	$ 83,208	$ 128,453	$ 94,499	$ 123,123	$ 123,500	$ 103,500	$ 103,500
5415 Energy Conservation	$ 61,634	$ 2,896					
5420 Community Safety Program	$ 67,343	$ 66,874	$ 70,410	$ 44,940	$ 85,700	$ 85,700	$ 87,800
5425 Miscellaneous Customer Service and Informational Expenses							
5505 Supervision							
5510 Demonstrating and Selling Expense							
5515 Advertising Expenses							
5520 Miscellaneous Sales Expense							
Total - Community Relations	$ 212,185	$ 198,223	$ 164,909	$ 168,063	$ 209,200	$ 189,200	$ 191,300
Account Description	**Last Rebasing Year (2010 Actuals)**	**2011 Actual**	**2012 Actual[2]**	**Bridge Year 2013[3] Actual to August 31**	**Bridge Year 2013[3] Projected to Year end**	**Bridge Year 2013[3]**	**Test Year 2014**
Administrative and General Expenses							
5605 Executive Salaries and Expenses	$ 47,825	$ 58,586	$ 43,940	$ 30,165	$ 46,900	$ 46,900	$ 37,800
5610 Management Salaries and Expenses	$ 813,654	$ 846,796	$ 875,407	$ 564,547	$ 846,200	$ 846,200	$ 895,500
5615 General Administrative Salaries and Expenses	$ 239,720	$ 263,518	$ 218,867	$ 137,399	$ 243,400	$ 243,400	$ 254,900
5620 Office Supplies and Expenses	$ 142,647	$ 143,528	$ 163,155	$ 139,271	$ 162,000	$ 177,000	$ 180,800
5625 Administrative Expense Transferred - Credit	-$ 189,237	-$ 189,294	-$ 189,060	-$ 41,431	-$ 179,400	-$ 179,400	-$ 184,400
5630 Outside Services Employed	$ 161,523	$ 250,058	$ 172,152	$ 20,054	$ 228,200	$ 228,200	$ 237,700
5635 Property Insurance	$ 207,712	$ 252,666	$ 252,666	$ 183,385	$ 279,100	$ 279,100	$ 287,500
5640 Injuries and Damages	$ 120,902	$ 178,277	$ 135,778	$ 158,364	$ 238,000	$ 229,700	$ 236,600
5645 OMERS Pensions and Benefits	$ 242,947	$ 327,707	$ 7,938	$ 148,689	$ 3,100	$ 3,100	$ 3,900
5646 Employee Pensions and OPEB							
5647 Employee Sick Leave							
5650 Franchise Requirements							
5655 Regulatory Expenses	$ 492,357	$ 481,307	$ 556,472	$ 393,515	$ 640,200	$ 640,200	$ 697,900
5660 General Advertising Expenses							
5665 Miscellaneous General Expenses	$ 36,937	$ 43,472	$ 79,368	$ 37,146	$ 97,100	$ 97,100	$ 101,300
5670 Rent							
5672 Lease Payment Charge							
5675 Maintenance of General Plant	$ 272,391	$ 307,551	$ 272,550	$ 162,494	$ 285,000	$ 299,100	$ 298,600
5680 Electrical Safety Authority Fees	$ 36,914	$ 36,813	$ 38,643	$ 39,740	$ 40,600	$ 40,600	$ 42,600
5681 Special Purpose Charge Expense							
5685 Independent Electricity System Operator Fees and Penalties							
5695 OM&A Contra Account	-$ 161,963	-$ 556,950	$ 41,257	-$ 9,477	$ -		
6205 Donations	$ 73,752	$ 26,370	$ 36,152	$ 1,750	$ 42,525	$ 42,525	$ 44,000
6205 Donations, Sub-account LEAP Funding	$ -	$ 47,475	$ 47,475	$ 47,475	$ 47,475	$ 47,475	$ 46,000
Total - Administrative and General Expenses	$ 2,538,081	$ 2,517,881	$ 2,752,760	$ 2,013,087	$ 3,020,400	$ 3,041,200	$ 3,180,700
Total OM&A	$ 12,344,709	$ 13,750,860	$ 16,479,881	$ 11,278,448	$ 17,560,100	$ 17,473,600	$ 18,567,200
Adjustments for non-recoverable items							
5681 Special Purpose Charge Expense							
6205 Donations[1]	$ 73,752	$ 26,370	$ 36,152	$ 1,750	$ 42,525	$ 42,525	$ 44,000
Total Recoverable OM&A	$ 12,270,957	$ 13,724,490	$ 16,443,729	$ 11,276,698	$ 17,517,575	$ 17,431,075	$ 18,523,200

[1] Account 6205 - Donations is generally non-recoverable. However, the sub-account LEAP funding of account 6205 is generally recoverable.

Note:

1. If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
2. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, 2011 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.
3. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, 2012 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.

End of Exhibit Four Interrogatories

Board Staff Exhibit Five Interrogatories

Exhibit 5 – Cost of Capital

5-Staff-29 Ref: Exhibit 5/Tab 1/Schedule 2, Exhibit 5/Tab 1/Schedule 4/Attachment 2, Exhibit 5/Tab 1/Schedule 4/Attachment 4, Appendix 2-OB (2014) – Affiliated Debt Rate

Table 5-6 shows that KWHI has proposed a 4.13% weighted average long-term cost of debt for 2014, subject to any update to be issued by the Board in accordance with the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (the "Cost of Capital Report"), issued December 11, 2009. This is composed of an Infrastructure Ontario loan with a rate of 4.28% and affiliated loans to the shareholders, the City of Kitchener and the Township of Wilmot, which attract the Board's deemed long-term debt rate.

The copy of the Promissory Note between KWHI and the City of Kitchener filed in Exhibit 5/Tab 1/Schedule 4/Attachment 2 states that the Established Rate for the Promissory Note, effective January 1, 2003, is the Ontario Energy Board Established Rate.

The Microsoft Excel version of Appendix 2-OB for 2014 corresponds with Table 5-6. However, the copy shown in the Application in Exhibit 5/Tab 1/Schedule 4/Attachment 4 shows a rate of 6.00% for the shareholder loans with the City of Kitchener and the Township of Wilmot.

a) Please confirm that the "Ontario Energy Board Established Rate" documented in the executed Promissory Note refers to the Board's issued deemed long-term debt rate. In the alternative, please explain.

Answer: Confirmed. The promissory note refers to the Board's issued deemed long-term debt rate.

b) Please explain the rate of 6.00%, rather than the deemed long-term debt rate, shown for the shareholder loans for 2014 in Exhibit 4/Tab 1/Schedule 4/Attachment 4.

Answer: The wrong table was copied in the rate filing. A revised version is included in Appendix A

5-Staff-30 Ref: Exhibit 5/Tab 1.Schedule 4 – Long-term Debt

In this exhibit, KWHI states:

> KWHI does not currently have plans to take on additional long term debt at this time. KWHI notes; however, that its cash balances have been decreasing at a rate of approximately $3,000,000 per year and the issuance of new debt over the next rebasing cycle may become unavoidable.

Please explain the reasons why the cash balance is decreasing by approximately $3 million per annum.

Answer: There are a number of reasons for this including:

- **A DVA rate rider effective May 1, 2010 through April 30, 2012 which refunded $5.774 million to customers;**
- **The Smart Meter Initiative**
- **A negative rate rider refunding account 1576 from cash for what is a non-cash item**
- **Increased accounts receivable as the cost of power increases;**
- **Increased funds required to replace aging infrastructure; and**
- **Increasing distribution expenses.**

End of Board Staff Exhibit Five Interrogatories

Energy Probe Exhibit Five Interrogatories

EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE

5-Energy Probe-50

Ref: Exhibit 5, Tab 1, Schedule 2

Has KWHI investigated the cost of replacing all or parts of the unsecured promissory notes from the two shareholders with financing from third parties? If not, why not? If yes, please provide all correspondence regarding amounts, term lengths, rates and other terms of any financing available to KWHI.

Answer: KWHI has not performed an investigation into the cost of replacing its promissory notes from its shareholders with financing from third parties. The shareholders are interested in maintaining a revenue stream per the current promissory note.

5-Energy Probe-51

Ref: Exhibit 5, Tab 1, Schedule 2 &
Exhibit 5, Tab 1, Schedule 3

Please confirm that KWHI will use the deemed long term debt rate issued by the Board for January 1, 2014 rates, which will be based on September, 2013 data and probably issued in November, 2013 rather than based on January, 2014 market interest rate information as stated in the evidence. If this cannot be confirmed for the deemed long term debt rate, return on equity rate and deemed short term debt rate, please explain.

Answer: Confirmed. KWHI will use the weighted average of the long term debts rates of its loan to Infrastructure Ontario (4.28%) and the Board's deemed long term debt rate for its shareholder debt.

5-Energy Probe-52

Ref: Exhibit 5, Tab 1, Schedule 4 &
Exhibit 5, Tab 1, Schedule 1

Please explain why the interest rate associated with the shareholder loans shown in the 2014 table in Appendix 2-OB of Exhibit 5, Tab 1, Schedule 4 is 6.0% rather than the 4.12% shown in Table 5-2 of Exhibit 5, Tab 1, Schedule 1.

Answer: See Board staff interrogatory 5-Staff-29 b).

End of Energy Probe Exhibit Five Interrogatories

No School Energy Coalition Exhibit Five Interrogatories

No VECC Exhibit Five Interrogatories

Board Staff Exhibit Six Interrogatories

Exhibit 6 – Revenue Requirement and Revenue Sufficiency/Deficiency

6-Staff-31 Ref: Exhibit 6/Tab 1/Schedule 2 /Table 6-6

Please augment Table 6-6 showing the achieved Return on Equity in each year, including the 2010 Board-approved and the 2013 bridge and 2014 test year estimates, and based on both actual and deemed capital structures.

Answer: See tables below:

Return on Actual Rate Base ($)

	2010 Board Approved	2009 Actual	2009 Actual vs. 2010 Board Approved	2010 Actual	2010 Actual vs. 2010 Board Approved	2010 Actual vs. 2009 Actual	2011 Actual	2011 Actual vs. 2010 Actual	2012 Actual	2012 Actual vs. 2011 Actual	2013 Bridge	2013 Bridge vs. 2012 Actual	2014 Test	2014 Test vs. 2013 Bridge
Total Operating Revenue	39,787,323	34,621,244	-13.0%	37,611,996	-5.5%	8.6%	40,278,148	7.1%	42,675,034	6.0%	36,328,523	-14.9%	39,453,868	8.6%
–														
Distribution Expenses	24,719,148	21,848,109	-11.6%	22,459,645	-9.1%	2.8%	24,162,972	7.6%	26,410,960	9.3%	24,976,427	-5.4%	26,480,853	6.0%
=														
Net Income Before PILs and Interest	15,068,175	12,773,136	-15.2%	15,152,351	0.6%	18.6%	16,115,175	6.4%	16,264,074	0.9%	11,352,096	-30.2%	12,973,015	14.3%
–														
PILs	3,254,024	3,167,708	-2.7%	2,217,629	-31.8%	-30.0%	2,374,409	7.1%	1,671,193	-29.6%	0	-100.0%	433,327	0.0%
=														
Net Income Before Interest	11,814,151	9,605,428	-18.7%	12,934,722	9.5%	34.7%	13,740,767	6.2%	14,592,881	6.2%	11,352,096	-22.2%	12,539,688	10.5%
–														
Interest Expense	5,446,469	4,877,571	-10.4%	5,080,436	-6.7%	4.2%	5,256,761	3.5%	5,834,702	11.0%	6,801,351	16.6%	5,019,405	-26.2%
=														
Net Income After Interest	6,367,682	4,727,857	-25.8%	7,854,286	23.3%	66.1%	8,484,005	8.0%	8,758,179	3.2%	4,550,745	-48.0%	7,520,283	65.3%
Actual Rate Base	161,616,283	154,644,648	-4.3%	162,907,438	0.8%	5.3%	174,264,763	7.0%	185,879,369	6.7%	201,820,490	8.6%	209,362,001	3.7%
Actual Equity	64,646,513	99,307,989	53.6%	101,326,013	56.7%	2.0%	109,874,046	8.4%	115,406,733	5.0%	116,241,852	0.7%	121,929,855	4.9%
Return on Equity	9.85%	4.76%	-51.7%	7.75%	-21.3%	62.8%	7.72%	-0.4%	7.59%	-1.7%	3.91%	-48.4%	6.17%	57.5%

Return on Deemed Rate Base ($)

	2010 Board Approved	2009 Actual	2009 Actual vs. 2010 Board Approved	2010 Actual	2010 Actual vs. 2010 Board Approved	2010 Actual vs. 2009 Actual	2011 Actual	2011 Actual vs. 2010 Actual	2012 Actual	2012 Actual vs. 2011 Actual	2013 Bridge	2013 Bridge vs. 2012 Actual	2014 Test	2014 Test vs. 2013 Bridge
Total Operating Revenue	39,787,323	34,621,244	-13.0%	37,611,996	-5.5%	8.6%	40,278,148	7.1%	42,675,034	6.0%	36,328,523	-14.9%	40,247,136	10.8%
–														
Distribution Expenses	24,719,148	21,848,109	-11.6%	22,459,645	-9.1%	2.8%	24,162,972	7.6%	26,410,960	9.3%	24,976,427	-5.4%	24,995,499	0.1%
=														
Net Income Before PILs and Interest	15,068,175	12,773,136	-15.2%	15,152,351	0.6%	18.6%	16,115,175	6.4%	16,264,074	0.9%	11,352,096	-30.2%	15,251,637	34.4%
–														
PILs	3,254,024	3,254,024	0.0%	3,254,024	0.0%	0.0%	3,254,024	0.0%	3,254,024	0.0%	3,254,024	0.0%	3,254,024	0.0%
=														
Net Income Before Interest	11,814,151	9,519,112	-19.4%	11,898,327	0.7%	25.0%	12,861,151	8.1%	13,010,050	1.2%	8,098,072	-37.8%	11,997,613	48.2%
–														
Interest Expense	5,446,469	5,446,469	0.0%	5,446,469	0.0%	0.0%	5,446,469	0.0%	5,446,469	0.0%	5,446,469	0.0%	5,446,469	0.0%
=														
Net Income After Interest	6,367,682	4,072,643	-36.0%	6,451,858	1.3%	58.4%	7,414,682	14.9%	7,563,581	2.0%	2,651,603	-64.9%	6,551,144	147.1%
Rate Base	161,616,283	147,725,922	-8.6%	161,616,283	0.0%	9.4%	161,616,283	0.0%	161,616,283	0.0%	161,616,283	0.0%	209,362,001	29.5%
Deemed Equity	64,646,513	64,646,513	0.0%	64,646,513	0.0%	0.0%	64,646,513	0.0%	64,646,513	0.0%	64,646,513	0.0%	121,929,855	88.6%
Return on Rate Base	9.85%	6.30%	-36.0%	7.36%	-25.3%	16.9%	7.96%	8.1%	8.05%	1.2%	5.01%	-37.8%	5.73%	14.4%

6-Staff-32 Ref: Exhibit 6/Tab 1/Schedule 3/Table 6-10

In this exhibit, in Table 6-10 and on the following page, KWHI describes the drivers of its revenue sufficiency. Table 6-10 is replicated below.

Table 6-10
Summary of the Components of Revenue Sufficiency

Driver	Increase (Decrease) from 2010 Board Approved ($)	Increase (Decrease) from 2010 Board Approved (%)	Impact on Revenue Sufficiency ($)	Impact on Revenue Sufficiency (%)	Evidentiary Reference
Net Fixed Assets	44,325,665	31.96%	(832,510)	36.5%	Exhibit 2
Working Capital	3,422,063	14.87%	(120,326)	5.3%	Exhibit 2
Cost of Capital (Deemed)	-1.32%	-18.06%	172,126	-7.6%	Exhibit 6
Distribution Expenses	276,351	1.12%	(1,556,197)	68.3%	Exhibit 4
PILs (Deemed)	(2,820,697)	-86.68%	(26,979)	1.2%	Exhibit 4
Other Revenue	177,688	9.55%	126,959	-5.6%	Exhibit 3
Transformer Ownership Allowance	(54,244)	-7.49%	(41,694)	1.5%	Exhibit 3
Throughput Revenue	(2,050,740)	-5.31%	(2,278,621)	100.0%	

a) Please explain the derivation of the entries in Table 6-10.

Answer: See below the table updated with the August 9, 2013 figures when the revenue sufficiency was updated to $793,268.

Summary of the Components of Revenue Deficiency

Drive	Increase (Decrease) from 2010 Board Approved ($)	Increase (Decrease) from 2010 Board Approved (%)	Impact on Revenue Deficiency ($)	Impact on Revenue Deficiency (%)	Evidentiary Reference
Net Fixed Assets	44,323,665	31.98%	(278,522)	35.1%	Exhibit 2
Working Capital	3,422,053	14.87%	(40,256)	5.1%	Exhibit 2
Cost of Capital (Deemed)	-1.32%	-18.06%	57,586	-7.3%	Exhibit 6
Distribution Expenses	1,761,705	7.13%	(551,576)	69.5%	Exhibit 4
PILs (Deemed)	(2,820,697)	-86.68%	(9,026)	1.1%	Exhibit 4
Other Revenue	177,688	9.55%	42,475	-5.4%	Exhibit 3
Transformer Ownership Allowance	(54,244)	-7.49%	(13,949)	1.8%	Exhibit 3
Throughput Revenue	(565,386)	-1.46%	(793,268)	100.0%	

The first column lists the drivers of the revenue requirement. The second two columns (Increase (Decrease) from 2010 Board Approved ($) and Increase (Decrease from 2010 Board Approved (%)) calculate the change from Board approved amounts from 2010 in both dollar and percentage amounts.

The revenue requirement is made of various components including the return on rate base (based on average net fixed assets and the working capital allowance), distribution expenses, amortization, interest and PILS. The table endeavours to calculate the breakdown of those different components based on their proportionate share of the entire revenue requirement.

As explained above, the fourth column calculates the proportionate impact of each of the drivers in the first column have on the entire revenue deficiency/sufficiency. The fifth column gives the amounts in percentage terms. The numbers used come directly from Table 6-2 from the evidence.

b) Transformer Ownership Allowance is listed as a driver of the revenue sufficiency. The overall revenue sufficiency of $2,278,621 corresponds with that shown in the RRWF for the June 21, 2013 updated Application. The RRWF calculates and summarizes the service revenue requirement and the base revenue requirement before the Transformer Ownership Allowance credit is added on for the purpose of factoring the recovery of the credit amount to be collected from customers in affected classes. In effect, the Transformer Ownership Allowance is treated as a pass-through cost and the utility is held harmless for compensating customers that provide their own transformation. In this case, please explain how the Transformer Ownership Allowance can be a driver of the revenue sufficiency for the service and base revenue requirement.

Answer: The transformer ownership allowance is not a driver of the revenue sufficiency *per se*; however, it is embedded in the figures for distribution revenue. It's inclusion in Table 6-10 was to show the change from 2010 Board approved as the transformer ownership allowance was included in the same table in KWHI's 2010 rate filing. In the original version, the total revenue requirement was grossed up for the total amount of the transformer ownership allowance and then reduced to get to net distribution revenue.

c) Please provide an update for Table 6-10 reflecting the revenue requirement as updated in the August 9, 2013 filing. This update should also reflect any changes that KWHI is making in responses to interrogatories from Board staff and other intervenors.

Answer: The table is adjusted below to exclude the transformer ownership allowance and to reflect new information resulting from the interrogatory process:

Summary of the Components of Revenue Deficiency

Drive	Increase (Decrease) from 2010 Board Approved ($)	Increase (Decrease) from 2010 Board Approved (%)	Impact on Revenue Deficiency ($)	Impact on Revenue Deficiency (%)	Evidentiary Reference
Net Fixed Assets	45,668,428	32.95%	(331,773)	36.1%	Exhibit 2
Working Capital	3,260,638	14.17%	(47,312)	5.1%	Exhibit 2
Cost of Capital (Deemed)	-1.32%	-18.06%	68,480	-7.4%	Exhibit 6
Distribution Expenses	1,655,582	6.70%	(649,624)	70.7%	Exhibit 4
PILs (Deemed)	(2,873,656)	-88.31%	(9,369)	1.0%	Exhibit 4
Other Revenue	177,688	9.55%	50,227	-5.5%	Exhibit 3
Throughput Revenue	(1,323,284)	-3.42%	(919,371)	100.0%	

End of Board Staff Exhibit Six Interrogatories

Energy Probe Exhibit Six Interrogatories

EXHIBIT 6 - CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

6-Energy Probe-53

Ref: All Interrogatories

a) Please provide a revised RRWF (live Excel spreadsheet) that reflects all changes and/or corrections made to the filing as a result of the interrogatory responses.

Answer: See attached revised RRWF

b) Please provide a tracking sheet that shows the original requested deficiency/sufficiency, the impact of each individual change/correction (with a reference to the interrogatory) that has been made, and the resulting deficiency/sufficiency request.

Answer: See table below:

Tracking Sheet - Revenue Sufficiency Changes through Interrogatory Process

Description	2014 Test August 9, 2013	2014 Test Interrogatories	Variance	References
Revenue:				
Revenue Deficiency	(793,268)	(919,371)	126,102	
Distribution Revenue	38,207,936	38,245,833	(37,897)	3-Energy Probe-20 GS>50kW load adjustment
Other Operating Revenue (Net)	2,039,200	2,039,200		
Accounting Changes Under CGAAP - Account 1576				
Total Revenue	39,453,868	39,365,662	88,206	
Costs and Expenses:				
Administrative & General, Billing & Collecting	7,261,800	7,261,800		
Operation & Maintenance	11,261,400	11,261,400		
Depreciation & Amortization	7,562,853	7,456,730	106,123	2-Energy Probe-5 Computer software reclassification
				2-Energy Probe-6 Updated 2013 CAPEX
				2-Energy Probe-10 Updated fixed asset continuity
				2-VECC-4 Updated contributed capital
Property Taxes	394,800	394,800		
Capital Taxes				
Deemed Interest	5,019,405	5,047,775	(28,370)	
Total Costs and Expenses	31,500,258	31,422,505	77,752	
Less OCT Included Above				
Total Costs and Expenses Net of OCT	31,500,258	31,422,505	77,752	
Utility Income Before Income Taxes	7,953,610	7,943,157	10,454	
Income Taxes:				
Corporate Income Taxes	433,327	380,368	52,959	
Total Income Taxes	433,327	380,368	52,959	
Utility Net Income	7,520,283	7,562,789	(42,506)	
Capital Tax Expense Calculation:				
Total Rate Base	209,362,001	210,545,349	(1,183,348)	
Income Tax Expense Calculation:				
Accounting Income	7,953,610	7,943,157	10,454	
Tax Adjustments to Accounting Income	(5,959,922)	(6,217,240)	257,318	4-Staff-27 2013 removal of 1576 from Schedule 1
Taxable Income	1,993,688	1,725,916	267,772	
Income Tax Expense before deductions	528,327	457,368	70,959	
Small Business Deduction	(35,000)	(35,000)		
Co-operative Education Credit	(6,000)	(18,000)	12,000	4-Energy Probe-46 Number of qualifying employees updated
				4-Energy Probe-49 Number of qualifying employees updated
ATTC (Provincial)	(50,000)	(20,000)	(30,000)	4-Energy Probe-46 Number of qualifying employees updated
				4-Energy Probe-49 Number of qualifying employees updated
ATTC (Federal)	(4,000)	(4,000)		4-Energy Probe-46 Number of qualifying employees updated
				4-Energy Probe-49 Number of qualifying employees updated
Total Miscellaneous Tax Deductions	(95,000)	(77,000)	(18,000)	
Income Tax Expense after deductions	433,327	380,368	52,959	
	26.50%	26.50%		
Actual Return on Rate Base:				
Rate Base	209,362,001	210,545,349	(1,183,348)	2-Energy Probe-5 Computer software reclassification
				2-Energy Probe-6 Updated 2013 CAPEX
				2-Energy Probe-10 Updated fixed asset continuity
				2-VECC-4 Updated contributed capital
Interest Expense	5,019,405	5,047,775	(28,370)	
Net Income	7,520,283	7,562,789	(42,506)	
Total Actual Return on Rate Base	12,539,688	12,610,564	(70,876)	
Regulatory Assets included for disposal - Type 1	(526,302)	(526,302)		
Regulatory Assets included for disposal - Type 2	211,064	161,851	49,213	
	(315,238)	(364,451)	49,213	
Changes to Regulatory Asset Pools				
General Pool	(315,238)	(364,451)	49,213	2-Staff-9 1531
				2-Staff-12 1531, 1532
Includes:				9-Staff-45 1531, 1532
LRAM (Included in general pool)	414,350	392,254	22,096	9-Staff-46 LRAMVA 1568
Renewable Connection Capital		7,079	(7,079)	9-Staff-47 LRAMVA 1568
Renewable Connection OM&A	37,405	3,209	34,196	9-VECC-38 LRAMVA 1568

End of Energy Probe Exhibit Six Interrogatories

No School Energy Coalition Exhibit Six Interrogatories

No VECC Exhibit Six Interrogatories

Board Staff Exhibit Seven Interrogatories

Exhibit 7 – Cost Allocation

7-Staff-33 Ref: Exhibit 7/Tab 1/Schedule 1, Exhibit 8/Tab 1/Schedule 1 – GS > 50 kW Class Split

a) On what basis did KWHI ascertain that "the cost to service customers above and below 1350 kW is not significantly different (beyond the cost of supplying and installing a transformer)?

Answer: KWHI's Conditions of Service does not differentiate the way customers are served in the GS>50 kW class regardless of whether they are greater or less than 1350 kW. All customers in this class are supplied from shared distribution lines. All customers are demand metered and billed monthly. Customers may be supplied from a KWHI transformer or their own transformer. Those that supply their own transformer receive the transformer allowance regardless of size. Some are primary metered while others are secondary metered. Some are supplied from overhead lines while others are supplied from underground cables. Indeed, there are customers of both types above and below 1350 kW and they are treated the same with respect to how they are supplied and served.

b) In the fixed/variable ("F/V") ratios shown in Table 8-5, KWHI documents a n F/V split of 23.3%/76.7% for the GS > 50 kW class compared to a 66.7%/33.3% split for Large Use. The proposed monthly service charge for GS > 50 kW customers is $237.32 versus $14,501.61 for Large Use customers. Customers in the GS 1350-4999 kW category would have attributes probably intermediate between many GS > 50 kW customers with demand below 1350 kW and Large Use customers. Has KWHI considered the issue of a more accurate cost allocation and a rate design better aligned with the cost to serve, including the F/V split, for GS 1350-4999 kW customers?

Answer: KWHI does not believe that the creation of a new customer rate class for the 24 customers that would be affected would be cost effective. KWHI believes that the added cost of creating, reclassifying and communicating to the affected customers plus ongoing tracking and reporting of the class might exceed any possible benefits. Without a full cost allocation study, KWHI cannot quantify the possible benefits; however, there are only 24 customers and regulatory cost alone would be high.

7-Staff-34 Ref: Exhibit 7/Tab 1/Schedule 1/page 3 – Wholesale Meters
KWHI has not identified any metering cost for the Embedded Distributor (worksheet I-7.1), and has not identified any cost of wholesale metering (Sub-account 1820-3 in worksheet I-3).
Please describe any meters that are owned and/or operated by KWHI that measure the load (kW) of Waterloo North, as distinct from the loads of customers, including the cost of such meters and O&M costs that are associated with them.

Answer: The Embedded Distributor, Waterloo North Hydro, owns, operates and maintains the wholesale revenue metering associated with Wellesley DS. KWHI has no costs associated with this meter point except for meter interrogation expense, which is minimal ($11 monthly) and included in KWHI's overall meter reading costs.

When wholesale revenue metering was originally installed at KWHI's transformer station, costs were capitalized and included as Station Equipment.

End of Board Staff Exhibit Seven Interrogatories

Energy Probe Exhibit Seven Interrogatories

7-Energy Probe-54

Ref: Exhibit 7, Tab 1, Schedule 1

Is Table 7-5 based on the changes discussed for Services, Billing and Collection and Meter Capital only? If no, what other changes are included in the changes shown in Table 7-5?

Answer: Yes, the comparison was done using the default weights for services, billing, collections, and meter capital as given and the revised weights as proposed by KWHI.

7-Energy Probe-55

Ref: Exhibit 7, Tab 1, Schedule 1

a) Please confirm that no billing and collection costs, meter reading costs or any administration costs have been allocated to the embedded distributor customer class. If confirmed, please explain why no costs of this type have been allocated to the customer.

Answer: KWHI was directed by the Board to include the Embedded Distributor in its cost allocation calculations through its 2010 rate application so KWHI did so; however, the cost

allocation model does not allocate any billing and collection costs, meter reading costs or any administration costs when the "pure" direct allocation method is used.

KWHI also filled out Appendix 2-Q to allocate costs to the embedded distributor and a different result was obtained, using the same numbers. At the time, KWHI worked with Board staff to try to fix the issues but was unable to attain the same results through the model. Unable to reconcile the differences, KWHI choose to stick with the determination of costs as per the cost allocation model.

b) Please confirm that no regulatory costs have been allocated to the embedded customer.

Answer: Confirmed. Administration fees; however, were allocated through Appendix 2Q. See above discussion.

c) Please confirm that additional costs were incurred in preparing the cost of service application as a result of the inclusion of the embedded customer class in the cost allocation model and need to calculate the amounts for direct allocation. Please provide an estimate of these costs.

Answer: There was additional time spent preparing the application for the embedded distributor, but as a percentage of the total hours spent on the application, the results would be immaterial (less than 0.01%). In addition, the costs would not be incremental to KWHI.

<u>7-Energy Probe-56</u>

Ref: August 9 Material &
Exhibit 8, Tab 3, Schedule 3

Please assume for the purposes of this interrogatory that the proposed revenue to cost ratios shown in Part (c) of Appendix 2-P in the August 9th material are set equal to the Status Quo Ratios values with the exception that the ratios for the Street Lighting and USL are reduced to 120% and the Embedded Distributor class is set to 100% and any revenue shortfall is recovered through an increase in the ratios for the Large User and Residential classes by setting them equal to one another to recover the revenue shortfall.

a) Please provide the revenue to cost ratio for the Large User and Residential classes required under this approach.

Answer: 95.0%

b) Please provide revised bill impacts based upon the above approach as shown in Appendix 2-W of Exhibit 8, Tab 3, Schedule 3, Attachment 1.

Answer: See below:

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 100 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 9.7600	1	$ 9.76	$ 12.5300	1	$ 12.53	$ 2.77	28.38%
Smart Meter Disposition Rate Rider	Monthly	$ 0.1300	1	$ 0.13	$ 0.1300	1	$ 0.13	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 1.6200	1	$ 1.62		1	$ -	-$ 1.62	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 2.0600	1	$ 2.06	$ 2.06	
Distribution Volumetric Rate	per kWh	$ 0.0173	100	$ 1.73	$ 0.0125	100	$ 1.25	-$ 0.48	-27.75%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	100	$ 0.03	$ 0.0003	100	$ 0.03	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0004	100	-$ 0.04	-$ 0.0004	100	-$ 0.04	$ -	
1576 Rate Rider	per kWh		100	$ -	-$ 0.0013	100	-$ 0.13	-$ 0.13	
Sub-Total A				$ 13.23			$ 15.83	**$ 2.60**	**19.65%**
Deferral/Variance Account Disposition Rate	per kWh		100	$ -	-$ 0.0003	100	-$ 0.03	-$ 0.03	
Global Adjustment Rate Rider	per kWh		100	$ -	$ 0.0002	100	$ 0.02	$ 0.02	
	per kWh		100	$ -		100	$ -	$ -	
Low Voltage Service Charge			100	$ -		100	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 13.23**			**$ 15.82**	**$ 2.59**	**19.58%**
RTSR - Network	per kWh	$ 0.0067	103	$ 0.69	$ 0.0072	104	$ 0.75	$ 0.05	7.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0014	103	$ 0.14	$ 0.0014	104	$ 0.14	$ 0.00	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 14.07**			**$ 16.71**	**$ 2.64**	**18.80%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	103	$ 0.45	$ 0.0044	104	$ 0.46	$ 0.00	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	103	$ 0.12	$ 0.0012	104	$ 0.12	$ 0.00	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	100	$ 0.70	$ 0.0070	100	$ 0.70	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0780	103	$ 8.05	$ 0.0780	104	$ 8.07	$ 0.02	0.30%
Energy - RPP - Tier 2	per kWh	$ 0.0910		$ -	$ 0.0910		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0670	66	$ 4.43	$ 0.0670	66	$ 4.44	$ 0.01	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	19	$ 1.93	$ 0.1040	19	$ 1.94	$ 0.01	0.30%
TOU - On Peak	per kW	$ 0.1240	19	$ 2.30	$ 0.1240	19	$ 2.31	$ 0.01	0.30%
Total Bill on RPP (before Taxes)				**$ 23.64**			**$ 26.31**	**$ 2.67**	**11.30%**
HST		13%		$ 3.07	13%		$ 3.42	$ 0.35	11.30%
Total Bill (including HST)				$ 26.72			$ 29.73	$ 3.02	11.30%
Ontario Clean Energy Benefit [1]				-$ 2.67			-$ 2.97	-$ 0.30	11.24%
Total Bill on RPP (including OCEB)				**$ 24.05**			**$ 26.76**	**$ 2.72**	**11.30%**
Total Bill on TOU (before Taxes)				**$ 24.25**			**$ 26.93**	**$ 2.67**	**11.02%**
HST		13%		$ 3.15	13%		$ 3.50	$ 0.35	11.02%
Total Bill (including HST)				$ 27.41			$ 30.43	$ 3.02	11.02%
Ontario Clean Energy Benefit [1]				-$ 2.74			-$ 3.04	-$ 0.30	10.95%
Total Bill on TOU (including OCEB)				**$ 24.67**			**$ 27.39**	**$ 2.72**	**11.03%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption **250** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 9.7600	1	$ 9.76	$ 12.5300	1	$ 12.53	$ 2.77	28.38%
Smart Meter Disposition Rate Rider	Monthly	$ 0.1300	1	$ 0.13	$ 0.1300	1	$ 0.13	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 1.6200	1	$ 1.62	$ -	1	$ -	-$ 1.62	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 2.0600	1	$ 2.06	$ 2.06	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0173	250	$ 4.33	$ 0.0125	250	$ 3.13	-$ 1.20	-27.75%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	250	$ 0.08	$ 0.0003	250	$ 0.08	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0004	250	-$ 0.10	-$ 0.0004	250	-$ 0.10	$ -	
1576 Rate Rider	per kWh	$ -	250	$ -	-$ 0.0013	250	-$ 0.33	-$ 0.33	
Sub-Total A				$ 15.81			$ 17.50	**$ 1.69**	**10.66%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	250	$ -	-$ 0.0003	250	-$ 0.08	-$ 0.08	
Global Adjustment Rate Rider	per kWh	$ -	250	$ -	$ 0.0002	250	$ 0.05	$ 0.05	
	per kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Low Voltage Service Charge		$ -	250	$ -	$ -	250	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 15.81**			**$ 17.47**	**$ 1.66**	**10.50%**
RTSR - Network	per kWh	$ 0.0067	258	$ 1.73	$ 0.0072	259	$ 1.86	$ 0.13	7.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0014	258	$ 0.36	$ 0.0014	259	$ 0.36	$ 0.00	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 17.90**			**$ 19.70**	**$ 1.80**	**10.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	258	$ 1.14	$ 0.0044	259	$ 1.14	$ 0.00	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	258	$ 0.31	$ 0.0012	259	$ 0.31	$ 0.00	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0780	258	$ 20.12	$ 0.0780	259	$ 20.19	$ 0.06	0.30%
Energy - RPP - Tier 2	per kWh	$ 0.0910		$ -	$ 0.0910		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0670	165	$ 11.06	$ 0.0670	166	$ 11.10	$ 0.03	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	46	$ 4.83	$ 0.1040	47	$ 4.84	$ 0.01	0.30%
TOU - On Peak	per kWh	$ 0.1240	46	$ 5.76	$ 0.1240	47	$ 5.78	$ 0.02	0.30%
Total Bill on RPP (before Taxes)				**$ 41.47**			**$ 43.33**	**$ 1.86**	**4.49%**
HST		13%		$ 5.39	13%		$ 5.63	$ 0.24	4.49%
Total Bill (including HST)				$ 46.86			$ 48.96	$ 2.10	4.49%
Ontario Clean Energy Benefit [1]				-$ 4.69			-$ 4.90	-$ 0.21	4.48%
Total Bill on RPP (including OCEB)				**$ 42.17**			**$ 44.06**	**$ 1.89**	**4.49%**
Total Bill on TOU (before Taxes)				**$ 43.00**			**$ 44.86**	**$ 1.87**	**4.34%**
HST		13%		$ 5.59	13%		$ 5.83	$ 0.24	4.34%
Total Bill (including HST)				$ 48.59			$ 50.69	$ 2.11	4.34%
Ontario Clean Energy Benefit [1]				-$ 4.86			-$ 5.07	-$ 0.21	4.32%
Total Bill on TOU (including OCEB)				**$ 43.73**			**$ 45.62**	**$ 1.90**	**4.34%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption **500** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.7600	1	$ 9.76	$ 12.5300	1	$ 12.53	$ 2.77	28.38%
Smart Meter Disposition Rate Rider	Monthly	$ 0.1300	1	$ 0.13	$ 0.1300	1	$ 0.13	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 1.6200	1	$ 1.62	$ -	1	$ -	-$ 1.62	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 2.0600	1	$ 2.06	$ 2.06	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0173	500	$ 8.65	$ 0.0125	500	$ 6.25	-$ 2.40	-27.75%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	500	$ 0.15	$ 0.0003	500	$ 0.15	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0004	500	-$ 0.20	-$ 0.0004	500	-$ 0.20	$ -	
1576 Rate Rider		$ -	500	$ -	-$ 0.0013	500	-$ 0.65	-$ 0.65	
Sub-Total A				$ 20.11			$ 20.27	**$ 0.16**	**0.80%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	500	$ -	-$ 0.0003	500	-$ 0.15	-$ 0.15	
Global Adjustment Rate Rider	per kWh	$ -	500	$ -	$ 0.0002	500	$ 0.10	$ 0.10	
	per kWh	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge		$ -	500	$ -	$ -	500	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.11**			**$ 20.22**	**$ 0.11**	**0.55%**
RTSR - Network	per kWh	$ 0.0067	516	$ 3.46	$ 0.0072	518	$ 3.73	$ 0.27	7.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0014	516	$ 0.72	$ 0.0014	518	$ 0.72	$ 0.00	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 24.29**			**$ 24.67**	**$ 0.38**	**1.57%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	516	$ 2.27	$ 0.0044	518	$ 2.28	$ 0.01	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	516	$ 0.62	$ 0.0012	518	$ 0.62	$ 0.00	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0780	516	$ 40.25	$ 0.0780	518	$ 40.37	$ 0.12	0.30%
Energy - RPP - Tier 2	per kWh	$ 0.0910		$ -	$ 0.0910		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0670	330	$ 22.13	$ 0.0670	331	$ 22.19	$ 0.07	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	93	$ 9.66	$ 0.1040	93	$ 9.69	$ 0.03	0.30%
TOU - On Peak	per kWh	$ 0.1240	93	$ 11.52	$ 0.1240	93	$ 11.55	$ 0.04	0.30%
Total Bill on RPP (before Taxes)				**$ 71.18**			**$ 71.69**	**$ 0.51**	**0.72%**
HST		13%		$ 9.25	13%		$ 9.32	$ 0.07	0.72%
Total Bill (including HST)				$ 80.43			$ 81.01	$ 0.58	0.72%
Ontario Clean Energy Benefit [1]				-$ 8.04			-$ 8.10	-$ 0.06	0.75%
Total Bill on RPP (including OCEB)				**$ 72.39**			**$ 72.91**	**$ 0.52**	**0.72%**
Total Bill on TOU (before Taxes)				**$ 74.23**			**$ 74.75**	**$ 0.52**	**0.70%**
HST		13%		$ 9.65	13%		$ 9.72	$ 0.07	0.70%
Total Bill (including HST)				$ 83.88			$ 84.47	$ 0.59	0.70%
Ontario Clean Energy Benefit [1]				-$ 8.39			-$ 8.45	-$ 0.06	0.72%
Total Bill on TOU (including OCEB)				**$ 75.49**			**$ 76.02**	**$ 0.53**	**0.70%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption **800** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.7600	1	$ 9.76	$ 12.5300	1	$ 12.53	$ 2.77	28.38%
Smart Meter Disposition Rate Rider	Monthly	$ 0.1300	1	$ 0.13	$ 0.1300	1	$ 0.13	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 1.6200	1	$ 1.62	$ -	1	$ -	-$ 1.62	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 2.0600	1	$ 2.06	$ 2.06	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0173	800	$ 13.84	$ 0.0125	800	$ 10.00	-$ 3.84	-27.75%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	800	$ 0.24	$ 0.0003	800	$ 0.24	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0004	800	-$ 0.32	-$ 0.0004	800	-$ 0.32	$ -	
1576 Rate Rider	per kWh	$ -	800	$ -	-$ 0.0013	800	-$ 1.04	-$ 1.04	
Sub-Total A				$ 25.27			$ 23.60	**-$ 1.67**	**-6.61%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	800	$ -	-$ 0.0003	800	-$ 0.24	-$ 0.24	
Global Adjustment Rate Rider	per kWh	$ -	800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Low Voltage Service Charge		$ -	800	$ -	$ -	800	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.27**			**$ 23.52**	**-$ 1.75**	**-6.93%**
RTSR - Network	per kWh	$ 0.0067	826	$ 5.53	$ 0.0072	828	$ 5.96	$ 0.43	7.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0014	826	$ 1.16	$ 0.0014	828	$ 1.16	$ 0.00	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.96**			**$ 30.64**	**-$ 1.32**	**-4.12%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	826	$ 3.63	$ 0.0044	828	$ 3.64	$ 0.01	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	826	$ 0.99	$ 0.0012	828	$ 0.99	$ 0.00	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	226	$ 20.53	$ 0.0910	228	$ 20.76	$ 0.23	1.11%
TOU - Off Peak	per kWh	$ 0.0670	528	$ 35.40	$ 0.0670	530	$ 35.51	$ 0.11	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	149	$ 15.46	$ 0.1040	149	$ 15.50	$ 0.05	0.30%
TOU - On Peak	per kWh	$ 0.1240	149	$ 18.43	$ 0.1240	149	$ 18.48	$ 0.06	0.30%
Total Bill on RPP (before Taxes)				**$ 109.76**			**$ 108.69**	**-$ 1.07**	**-0.98%**
HST		13%		$ 14.27	13%		$ 14.13	-$ 0.14	-0.98%
Total Bill (including HST)				$ 124.03			$ 122.82	-$ 1.21	-0.98%
Ontario Clean Energy Benefit [1]				-$ 12.40			-$ 12.28	$ 0.12	-0.97%
Total Bill on RPP (including OCEB)				**$ 111.63**			**$ 110.54**	**-$ 1.09**	**-0.98%**
Total Bill on TOU (before Taxes)				**$ 111.72**			**$ 110.62**	**-$ 1.09**	**-0.98%**
HST		13%		$ 14.52	13%		$ 14.38	-$ 0.14	-0.98%
Total Bill (including HST)				$ 126.24			$ 125.01	-$ 1.23	-0.98%
Ontario Clean Energy Benefit [1]				-$ 12.62			-$ 12.50	$ 0.12	-0.95%
Total Bill on TOU (including OCEB)				**$ 113.62**			**$ 112.51**	**-$ 1.11**	**-0.98%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption **1000** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.7600	1	$ 9.76	$ 12.5300	1	$ 12.53	$ 2.77	28.38%
Smart Meter Disposition Rate Rider	Monthly	$ 0.1300	1	$ 0.13	$ 0.1300	1	$ 0.13	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 1.6200	1	$ 1.62	$ -	1	$ -	-$ 1.62	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 2.0600	1	$ 2.06	$ 2.06	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0173	1000	$ 17.30	$ 0.0125	1000	$ 12.50	-$ 4.80	-27.75%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	1000	$ 0.30	$ 0.0003	1000	$ 0.30	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0004	1000	-$ 0.40	-$ 0.0004	1000	-$ 0.40	$ -	
1576 Rate Rider	per kWh	$ -	1000	$ -	-$ 0.0013	1000	-$ 1.30	-$ 1.30	
Sub-Total A				$ 28.71			$ 25.82	**-$ 2.89**	**-10.07%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	1000	$ -	-$ 0.0003	1000	-$ 0.30	-$ 0.30	
Global Adjustment Rate Rider	per kWh	$ -	1000	$ -	$ 0.0002	1000	$ 0.20	$ 0.20	
	per kWh	$ -	1000	$ -	$ -	1000	$ -	$ -	
Low Voltage Service Charge		$ -	1000	$ -	$ -	1000	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.71**			**$ 25.72**	**-$ 2.99**	**-10.41%**
RTSR - Network	per kWh	$ 0.0067	1032	$ 6.91	$ 0.0072	1035	$ 7.45	$ 0.54	7.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0014	1032	$ 1.44	$ 0.0014	1035	$ 1.45	$ 0.00	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 37.07**			**$ 34.62**	**-$ 2.45**	**-6.60%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1032	$ 4.54	$ 0.0044	1035	$ 4.55	$ 0.01	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1032	$ 1.24	$ 0.0012	1035	$ 1.24	$ 0.00	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	432	$ 39.31	$ 0.0910	435	$ 39.60	$ 0.29	0.73%
TOU - Off Peak	per kWh	$ 0.0670	660	$ 44.25	$ 0.0670	662	$ 44.39	$ 0.13	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	186	$ 19.32	$ 0.1040	186	$ 19.38	$ 0.06	0.30%
TOU - On Peak	per kWh	$ 0.1240	186	$ 23.03	$ 0.1240	186	$ 23.10	$ 0.07	0.30%
Total Bill on RPP (before Taxes)				**$ 136.21**			**$ 134.07**	**-$ 2.14**	**-1.57%**
HST		13%		$ 17.71	13%		$ 17.43	-$ 0.28	-1.57%
Total Bill (including HST)				$ 153.92			$ 151.50	-$ 2.42	-1.57%
Ontario Clean Energy Benefit [1]				-$ 15.39			-$ 15.15	$ 0.24	-1.56%
Total Bill on RPP (including OCEB)				**$ 138.53**			**$ 136.35**	**-$ 2.18**	**-1.58%**
Total Bill on TOU (before Taxes)				**$ 136.70**			**$ 134.54**	**-$ 2.17**	**-1.58%**
HST		13%		$ 17.77	13%		$ 17.49	-$ 0.28	-1.58%
Total Bill (including HST)				$ 154.48			$ 152.03	-$ 2.45	-1.58%
Ontario Clean Energy Benefit [1]				-$ 15.45			-$ 15.20	$ 0.25	-1.62%
Total Bill on TOU (including OCEB)				**$ 139.03**			**$ 136.83**	**-$ 2.20**	**-1.58%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption **1500** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.7600	1	$ 9.76	$ 12.5300	1	$ 12.53	$ 2.77	28.38%
Smart Meter Disposition Rate Rider	Monthly	$ 0.1300	1	$ 0.13	$ 0.1300	1	$ 0.13	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 1.6200	1	$ 1.62	$ -	1	$ -	-$ 1.62	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 2.0600	1	$ 2.06	$ 2.06	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0173	1500	$ 25.95	$ 0.0125	1500	$ 18.75	-$ 7.20	-27.75%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	1500	$ 0.45	$ 0.0003	1500	$ 0.45	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0004	1500	-$ 0.60	-$ 0.0004	1500	-$ 0.60	$ -	
1576 Rate Rider	per kWh	$ -	1500	$ -	-$ 0.0013	1500	-$ 1.95	-$ 1.95	
Sub-Total A				$ 37.31			$ 31.37	**-$ 5.94**	**-15.92%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	1500	$ -	-$ 0.0003	1500	-$ 0.45	-$ 0.45	
Global Adjustment Rate Rider	per kWh	$ -	1500	$ -	$ 0.0002	1500	$ 0.30	$ 0.30	
	per kWh	$ -	1500	$ -	$ -	1500	$ -	$ -	
Low Voltage Service Charge		$ -	1500	$ -	$ -	1500	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.31**			**$ 31.22**	**-$ 6.09**	**-16.32%**
RTSR - Network	per kWh	$ 0.0067	1548	$ 10.37	$ 0.0072	1553	$ 11.18	$ 0.81	7.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0014	1548	$ 2.17	$ 0.0014	1553	$ 2.17	$ 0.01	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 49.85**			**$ 44.57**	**-$ 5.28**	**-10.58%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1548	$ 6.81	$ 0.0044	1553	$ 6.83	$ 0.02	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1548	$ 1.86	$ 0.0012	1553	$ 1.86	$ 0.01	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	948	$ 86.27	$ 0.0910	953	$ 86.70	$ 0.43	0.50%
TOU - Off Peak	per kWh	$ 0.0670	991	$ 66.38	$ 0.0670	994	$ 66.58	$ 0.20	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	279	$ 28.98	$ 0.1040	279	$ 29.07	$ 0.09	0.30%
TOU - On Peak	per kWh	$ 0.1240	279	$ 34.55	$ 0.1240	279	$ 34.66	$ 0.11	0.30%
Total Bill on RPP (before Taxes)				**$ 202.34**			**$ 197.52**	**-$ 4.82**	**-2.38%**
HST		13%		$ 26.30	13%		$ 25.68	-$ 0.63	-2.38%
Total Bill (including HST)				$ 228.64			$ 223.19	-$ 5.45	-2.38%
Ontario Clean Energy Benefit [1]				-$ 22.86			-$ 22.32	$ 0.54	-2.36%
Total Bill on RPP (including OCEB)				**$ 205.78**			**$ 200.87**	**-$ 4.91**	**-2.38%**
Total Bill on TOU (before Taxes)				**$ 199.18**			**$ 194.32**	**-$ 4.85**	**-2.44%**
HST		13%		$ 25.89	13%		$ 25.26	-$ 0.63	-2.44%
Total Bill (including HST)				$ 225.07			$ 219.58	-$ 5.48	-2.44%
Ontario Clean Energy Benefit [1]				-$ 22.51			-$ 21.96	$ 0.55	-2.44%
Total Bill on TOU (including OCEB)				**$ 202.56**			**$ 197.62**	**-$ 4.93**	**-2.44%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption **2000** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.7600	1	$ 9.76	$ 12.5300	1	$ 12.53	$ 2.77	28.38%
Smart Meter Disposition Rate Rider	Monthly	$ 0.1300	1	$ 0.13	$ 0.1300	1	$ 0.13	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 1.6200	1	$ 1.62	$ -	1	$ -	-$ 1.62	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 2.0600	1	$ 2.06	$ 2.06	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0173	2000	$ 34.60	$ 0.0125	2000	$ 25.00	-$ 9.60	-27.75%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	2000	$ 0.60	$ 0.0003	2000	$ 0.60	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0004	2000	-$ 0.80	-$ 0.0004	2000	-$ 0.80	$ -	
1576 Rate Rider		$ -	2000	$ -	-$ 0.0013	2000	-$ 2.60	-$ 2.60	
Sub-Total A				$ 45.91			$ 36.92	**-$ 8.99**	**-19.58%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	2000	$ -	-$ 0.0003	2000	-$ 0.60	-$ 0.60	
Global Adjustment Rate Rider	per kWh	$ -	2000	$ -	$ 0.0002	2000	$ 0.40	$ 0.40	
	per kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
Low Voltage Service Charge		$ -	2000	$ -	$ -	2000	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 45.91**			**$ 36.72**	**-$ 9.19**	**-20.02%**
RTSR - Network	per kWh	$ 0.0067	2064	$ 13.83	$ 0.0072	2070	$ 14.91	$ 1.08	7.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0014	2064	$ 2.89	$ 0.0014	2070	$ 2.90	$ 0.01	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 62.63**			**$ 54.52**	**-$ 8.10**	**-12.94%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2064	$ 9.08	$ 0.0044	2070	$ 9.11	$ 0.03	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2064	$ 2.48	$ 0.0012	2070	$ 2.48	$ 0.01	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	1464	$ 133.22	$ 0.0910	1470	$ 133.80	$ 0.57	0.43%
TOU - Off Peak	per kWh	$ 0.0670	1321	$ 88.50	$ 0.0670	1325	$ 88.77	$ 0.27	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	372	$ 38.64	$ 0.1040	373	$ 38.76	$ 0.12	0.30%
TOU - On Peak	per kWh	$ 0.1240	372	$ 46.07	$ 0.1240	373	$ 46.21	$ 0.14	0.30%
Total Bill on RPP (before Taxes)				**$ 268.46**			**$ 260.96**	**-$ 7.50**	**-2.79%**
HST		13%		$ 34.90	13%		$ 33.93	-$ 0.97	-2.79%
Total Bill (including HST)				$ 303.36			$ 294.89	-$ 8.47	-2.79%
Ontario Clean Energy Benefit [1]				-$ 30.34			-$ 29.49	$ 0.85	-2.80%
Total Bill on RPP (including OCEB)				**$ 273.02**			**$ 265.40**	**-$ 7.62**	**-2.79%**
Total Bill on TOU (before Taxes)				**$ 261.65**			**$ 254.11**	**-$ 7.54**	**-2.88%**
HST		13%		$ 34.01	13%		$ 33.03	-$ 0.98	-2.88%
Total Bill (including HST)				$ 295.66			$ 287.14	-$ 8.52	-2.88%
Ontario Clean Energy Benefit [1]				-$ 29.57			-$ 28.71	$ 0.86	-2.91%
Total Bill on TOU (including OCEB)				**$ 266.09**			**$ 258.43**	**-$ 7.66**	**-2.88%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **GS<50kW**

Consumption **1000** **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 25.7100	1	$ 25.71	$ 25.7100	1	$ 25.71	$ -	
Smart Meter Disposition Rate Rider	Monthly	$ 8.4200	1	$ 8.42	$ 8.4200	1	$ 8.42	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 5.5500	1	$ 5.55	$ -	1	$ -	-$ 5.55	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 8.4200	1	$ 8.42	$ 8.42	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0124	1000	$ 12.40	$ 0.0119	1000	$ 11.90	-$ 0.50	-4.03%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	1000	$ 0.10	$ 0.0001	1000	$ 0.10	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0003	1000	-$ 0.30	-$ 0.0003	1000	-$ 0.30	$ -	
1576 Rate Rider		$ -	1000	$ -	-$ 0.0010	1000	-$ 1.00	-$ 1.00	
Sub-Total A				$ 51.88			$ 53.25	**$ 1.37**	**2.64%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	1000	$ -	$ 0.0001	1000	$ 0.10	$ 0.10	
Global Adjustment Rate Rider	per kWh	$ -	1000	$ -	$ 0.0005	1000	$ 0.50	$ 0.50	
		$ -	1000	$ -		1000	$ -	$ -	
Low Voltage Service Charge		$ -	1000	$ -	$ -	1000	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 51.88**			**$ 53.85**	**$ 1.97**	**3.80%**
RTSR - Network	per kWh	$ 0.0058	1032	$ 5.99	$ 0.0062	1035	$ 6.42	$ 0.43	7.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	1032	$ 1.34	$ 0.0013	1035	$ 1.35	$ 0.00	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 59.21**			**$ 61.61**	**$ 2.41**	**4.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1032	$ 4.54	$ 0.0044	1035	$ 4.55	$ 0.01	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1032	$ 1.24	$ 0.0012	1035	$ 1.24	$ 0.00	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1035	$ 7.25	$ 0.25	3.51%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	432	$ 39.31	$ 0.0910	435	$ 39.60	$ 0.29	0.73%
TOU - Off Peak	per kWh	$ 0.0670	660	$ 44.25	$ 0.0670	662	$ 44.39	$ 0.13	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	186	$ 19.32	$ 0.1040	186	$ 19.38	$ 0.06	0.30%
TOU - On Peak	per kWh	$ 0.1240	186	$ 23.03	$ 0.1240	186	$ 23.10	$ 0.07	0.30%
Total Bill on RPP (before Taxes)				**$ 158.35**			**$ 161.30**	**$ 2.96**	**1.87%**
HST		13%		$ 20.59	13%		$ 20.97	$ 0.38	1.87%
Total Bill (including HST)				$ 178.93			$ 182.27	$ 3.34	1.87%
Ontario Clean Energy Benefit [1]				-$ 17.89			-$ 18.23	-$ 0.34	1.90%
Total Bill on RPP (including OCEB)				**$ 161.04**			**$ 164.04**	**$ 3.00**	**1.86%**
Total Bill on TOU (before Taxes)				**$ 158.84**			**$ 161.78**	**$ 2.93**	**1.85%**
HST		13%		$ 20.65	13%		$ 21.03	$ 0.38	1.85%
Total Bill (including HST)				$ 179.49			$ 182.81	$ 3.32	1.85%
Ontario Clean Energy Benefit [1]				-$ 17.95			-$ 18.28	-$ 0.33	1.84%
Total Bill on TOU (including OCEB)				**$ 161.54**			**$ 164.53**	**$ 2.99**	**1.85%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **GS<50kW**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 25.7100	1	$ 25.71	$ 25.7100	1	$ 25.71	$ -	
Smart Meter Disposition Rate Rider	Monthly	$ 8.4200	1	$ 8.42	$ 8.4200	1	$ 8.42	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 5.5500	1	$ 5.55	$ -	1	$ -	-$ 5.55	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 8.4200	1	$ 8.42	$ 8.42	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0124	2000	$ 24.80	$ 0.0119	2000	$ 23.80	-$ 1.00	-4.03%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	2000	$ 0.20	$ 0.0001	2000	$ 0.20	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0003	2000	-$ 0.60	-$ 0.0003	2000	-$ 0.60	$ -	
1576 Rate Rider	per kWh	$ -	2000	$ -	-$ 0.0010	2000	-$ 2.00	-$ 2.00	
Sub-Total A				$ 64.08			$ 63.95	**-$ 0.13**	**-0.20%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	2000	$ -	$ 0.0001	2000	$ 0.20	$ 0.20	
Global Adjustment Rate Rider	per kWh	$ -	2000	$ -	$ 0.0005	2000	$ 1.00	$ 1.00	
		$ -	2000	$ -	$ -	2000	$ -	$ -	
Low Voltage Service Charge		$ -	2000	$ -	$ -	2000	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 64.08**			**$ 65.15**	**$ 1.07**	**1.67%**
RTSR - Network	per kWh	$ 0.0058	2064	$ 11.97	$ 0.0062	2070	$ 12.84	$ 0.86	7.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	2064	$ 2.68	$ 0.0013	2070	$ 2.69	$ 0.01	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 78.73**			**$ 80.68**	**$ 1.94**	**2.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2064	$ 9.08	$ 0.0044	2070	$ 9.11	$ 0.03	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2064	$ 2.48	$ 0.0012	2070	$ 2.48	$ 0.01	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2070	$ 14.49	$ 0.49	3.51%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	1464	$ 133.22	$ 0.0910	1470	$ 133.80	$ 0.57	0.43%
TOU - Off Peak	per kWh	$ 0.0670	1321	$ 88.50	$ 0.0670	1325	$ 88.77	$ 0.27	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	372	$ 38.64	$ 0.1040	373	$ 38.76	$ 0.12	0.30%
TOU - On Peak	per kWh	$ 0.1240	372	$ 46.07	$ 0.1240	373	$ 46.21	$ 0.14	0.30%
Total Bill on RPP (before Taxes)				**$ 284.57**			**$ 287.61**	**$ 3.04**	**1.07%**
HST		13%		$ 36.99	13%		$ 37.39	$ 0.40	1.07%
Total Bill (including HST)				$ 321.56			$ 325.00	$ 3.44	1.07%
Ontario Clean Energy Benefit [1]				-$ 32.16			-$ 32.50	-$ 0.34	1.06%
Total Bill on RPP (including OCEB)				**$ 289.40**			**$ 292.50**	**$ 3.10**	**1.07%**
Total Bill on TOU (before Taxes)				**$ 277.75**			**$ 280.75**	**$ 3.00**	**1.08%**
HST		13%		$ 36.11	13%		$ 36.50	$ 0.39	1.08%
Total Bill (including HST)				$ 313.86			$ 317.25	$ 3.39	1.08%
Ontario Clean Energy Benefit [1]				-$ 31.39			-$ 31.72	-$ 0.33	1.05%
Total Bill on TOU (including OCEB)				**$ 282.47**			**$ 285.53**	**$ 3.06**	**1.08%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **GS<50kW**

Consumption **5000** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 25.7100	1	$ 25.71	$ 25.7100	1	$ 25.71	$ -	
Smart Meter Disposition Rate Rider	Monthly	$ 8.4200	1	$ 8.42	$ 8.4200	1	$ 8.42	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 5.5500	1	$ 5.55	$ -	1	$ -	-$ 5.55	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 8.4200	1	$ 8.42	$ 8.42	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0124	5000	$ 62.00	$ 0.0119	5000	$ 59.50	-$ 2.50	-4.03%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	5000	$ 0.50	$ 0.0001	5000	$ 0.50	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0003	5000	-$ 1.50	-$ 0.0003	5000	-$ 1.50	$ -	
1576 Rate Rider		$ -	5000	$ -	-$ 0.0010	5000	-$ 5.00	-$ 5.00	
Sub-Total A				$ 100.68			$ 96.05	**-$ 4.63**	**-4.60%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	5000	$ -	$ 0.0001	5000	$ 0.50	$ 0.50	
Global Adjustment Rate Rider	per kWh	$ -	5000	$ -	$ 0.0005	5000	$ 2.50	$ 2.50	
		$ -	5000	$ -	$ -	5000	$ -	$ -	
Low Voltage Service Charge		$ -	5000	$ -	$ -	5000	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 100.68**			**$ 99.05**	**-$ 1.63**	**-1.62%**
RTSR - Network	per kWh	$ 0.0058	5160	$ 29.93	$ 0.0062	5176	$ 32.09	$ 2.16	7.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	5160	$ 6.71	$ 0.0013	5176	$ 6.73	$ 0.02	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 137.32**			**$ 137.87**	**$ 0.55**	**0.40%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	5160	$ 22.70	$ 0.0044	5176	$ 22.77	$ 0.07	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	5160	$ 6.19	$ 0.0012	5176	$ 6.21	$ 0.02	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5000	$ 35.00	$ 0.0070	5176	$ 36.23	$ 1.23	3.51%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	4560	$ 414.96	$ 0.0910	4576	$ 416.39	$ 1.43	0.34%
TOU - Off Peak	per kWh	$ 0.0670	3302	$ 221.26	$ 0.0670	3312	$ 221.93	$ 0.67	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	929	$ 96.60	$ 0.1040	932	$ 96.89	$ 0.29	0.30%
TOU - On Peak	per kWh	$ 0.1240	929	$ 115.17	$ 0.1240	932	$ 115.52	$ 0.35	0.30%
Total Bill on RPP (before Taxes)				**$ 663.22**			**$ 666.52**	**$ 3.30**	**0.50%**
HST		13%		$ 86.22	13%		$ 86.65	$ 0.43	0.50%
Total Bill (including HST)				$ 749.44			$ 753.17	$ 3.73	0.50%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 749.44**			**$ 753.17**	**$ 3.73**	**0.50%**
Total Bill on TOU (before Taxes)				**$ 634.49**			**$ 637.68**	**$ 3.19**	**0.50%**
HST		13%		$ 82.48	13%		$ 82.90	$ 0.41	0.50%
Total Bill (including HST)				$ 716.97			$ 720.58	$ 3.60	0.50%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 716.97**			**$ 720.58**	**$ 3.60**	**0.50%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **GS<50kW**

Consumption **10000** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 25.7100	1	$ 25.71	$ 25.7100	1	$ 25.71	$ -	
Smart Meter Disposition Rate Rider	Monthly	$ 8.4200	1	$ 8.42	$ 8.4200	1	$ 8.42	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 5.5500	1	$ 5.55	$ -	1	$ -	-$ 5.55	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 8.4200	1	$ 8.42	$ 8.42	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0124	10000	$ 124.00	$ 0.0119	10000	$ 119.00	-$ 5.00	-4.03%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	10000	$ 1.00	$ 0.0001	10000	$ 1.00	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0003	10000	-$ 3.00	-$ 0.0003	10000	-$ 3.00	$ -	
1576 Rate Rider		$ -	10000	$ -	-$ 0.0010	10000	-$ 10.00	-$ 10.00	
Sub-Total A				$ 161.68			$ 149.55	**-$ 12.13**	**-7.50%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	10000	$ -	$ 0.0001	10000	$ 1.00	$ 1.00	
Global Adjustment Rate Rider	per kWh	$ -	10000	$ -	$ 0.0005	10000	$ 5.00	$ 5.00	
		$ -	10000	$ -	$ -	10000	$ -	$ -	
Low Voltage Service Charge		$ -	10000	$ -	$ -	10000	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 161.68**			**$ 155.55**	**-$ 6.13**	**-3.79%**
RTSR - Network	per kWh	$ 0.0058	10320	$ 59.86	$ 0.0062	10351	$ 64.18	$ 4.32	7.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	10320	$ 13.42	$ 0.0013	10351	$ 13.46	$ 0.04	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 234.95**			**$ 233.19**	**-$ 1.77**	**-0.75%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	10320	$ 45.41	$ 0.0044	10351	$ 45.55	$ 0.14	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	10320	$ 12.38	$ 0.0012	10351	$ 12.42	$ 0.04	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10000	$ 70.00	$ 0.0070	10351	$ 72.46	$ 2.46	3.51%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	9720	$ 884.52	$ 0.0910	9751	$ 887.38	$ 2.86	0.32%
TOU - Off Peak	per kWh	$ 0.0670	6605	$ 442.52	$ 0.0670	6625	$ 443.87	$ 1.35	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	1858	$ 193.19	$ 0.1040	1863	$ 193.78	$ 0.59	0.30%
TOU - On Peak	per kWh	$ 0.1240	1858	$ 230.34	$ 0.1240	1863	$ 231.04	$ 0.70	0.30%
Total Bill on RPP (before Taxes)				**$1,294.31**			**$1,298.04**	**$ 3.73**	**0.29%**
HST		13%		$ 168.26	13%		$ 168.75	$ 0.48	0.29%
Total Bill (including HST)				$1,462.57			$1,466.79	$ 4.21	0.29%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$1,462.57**			**$1,466.79**	**$ 4.21**	**0.29%**
Total Bill on TOU (before Taxes)				**$1,229.05**			**$1,232.55**	**$ 3.51**	**0.29%**
HST		13%		$ 159.78	13%		$ 160.23	$ 0.46	0.29%
Total Bill (including HST)				$1,388.82			$1,392.79	$ 3.96	0.29%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$1,388.82**			**$1,392.79**	**$ 3.96**	**0.29%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **GS<50kW**

Consumption **15000** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 25.7100	1	$ 25.71	$ 25.7100	1	$ 25.71	$ -	
Smart Meter Disposition Rate Rider	Monthly	$ 8.4200	1	$ 8.42	$ 8.4200	1	$ 8.42	$ -	
Smart Meter Incremental Revenue Rate Rider	Monthly	$ 5.5500	1	$ 5.55	$ -	1	$ -	-$ 5.55	-100.00%
Stranded Meter Rate Rider	Monthly	$ -	1	$ -	$ 8.4200	1	$ 8.42	$ 8.42	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0124	15000	$ 186.00	$ 0.0119	15000	$ 178.50	-$ 7.50	-4.03%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	15000	$ 1.50	$ 0.0001	15000	$ 1.50	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0003	15000	-$ 4.50	-$ 0.0003	15000	-$ 4.50	$ -	
1576 Rate Rider		$ -	15000	$ -	-$ 0.0010	15000	-$ 15.00	-$ 15.00	
Sub-Total A				$ 222.68			$ 203.05	**-$ 19.63**	**-8.82%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	15000	$ -	$ 0.0001	15000	$ 1.50	$ 1.50	
Global Adjustment Rate Rider	per kWh	$ -	15000	$ -	$ 0.0005	15000	$ 7.50	$ 7.50	
		$ -	15000	$ -	$ -	15000	$ -	$ -	
Low Voltage Service Charge		$ -	15000	$ -	$ -	15000	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 222.68**			**$ 212.05**	**-$ 10.63**	**-4.77%**
RTSR - Network	per kWh	$ 0.0058	15480	$ 89.78	$ 0.0062	15527	$ 96.27	$ 6.48	7.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	15480	$ 20.12	$ 0.0013	15527	$ 20.19	$ 0.06	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 332.59**			**$ 328.50**	**-$ 4.08**	**-1.23%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15480	$ 68.11	$ 0.0044	15527	$ 68.32	$ 0.21	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	15480	$ 18.58	$ 0.0012	15527	$ 18.63	$ 0.06	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15000	$ 105.00	$ 0.0070	15527	$ 108.69	$ 3.69	3.51%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	14880	$1,354.08	$ 0.0910	14927	$1,358.37	$ 4.29	0.32%
TOU - Off Peak	per kWh	$ 0.0670	9907	$ 663.78	$ 0.0670	9937	$ 665.80	$ 2.02	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	2786	$ 289.79	$ 0.1040	2795	$ 290.67	$ 0.88	0.30%
TOU - On Peak	per kWh	$ 0.1240	2786	$ 345.51	$ 0.1240	2795	$ 346.57	$ 1.05	0.30%
Total Bill on RPP (before Taxes)				**$1,925.41**			**$1,929.56**	**$ 4.16**	**0.22%**
HST		13%		$ 250.30	13%		$ 250.84	$ 0.54	0.22%
Total Bill (including HST)				$2,175.71			$2,180.41	$ 4.70	0.22%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$2,175.71**			**$2,180.41**	**$ 4.70**	**0.22%**
Total Bill on TOU (before Taxes)				**$1,823.61**			**$1,827.43**	**$ 3.82**	**0.21%**
HST		13%		$ 237.07	13%		$ 237.57	$ 0.50	0.21%
Total Bill (including HST)				$2,060.68			$2,065.00	$ 4.32	0.21%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$2,060.68**			**$2,065.00**	**$ 4.32**	**0.21%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **GS>50kW**

Consumption **60** kW **20000** kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 3

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 237.7200	1	$ 237.72	$ 237.7200	1	$ 237.72	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -			$ -				
Distribution Volumetric Rate	per kW	$ 4.0593	60	$ 243.56	$ 3.9554	60	$ 237.32	-$ 6.23	-2.56%
LRAM & SSM Rate Rider	per kW	$ 0.0172	60	$ 1.03	$ 0.0172	60	$ 1.03	$ -	
Tax Change Rate Rider	per kW	-$ 0.0676	60	-$ 4.06	-$ 0.0676	60	-$ 4.06	$ -	
1576 Rate Rider		$ -	60	$ -	-$ 0.2316	60	-$ 13.90	-$ 13.90	
Sub-Total A				$ 478.25			$ 458.12	**-$ 20.13**	**-4.21%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	60	$ -	-$ 0.0756	60	-$ 4.54	-$ 4.54	
Global Adjustment Rate Rider	per kW	$ -	60	$ -	$ 1.1133	60	$ 66.80	$ 66.80	
		$ -	60	$ -		60	$ -	$ -	
Low Voltage Service Charge		$ -	60	$ -	$ -	60	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 478.25**			**$ 520.39**	**$ 42.13**	**8.81%**
RTSR - Network	per kW	$ 3.0721	62	$ 190.22	$ 3.2836	62	$ 203.94	$ 13.72	7.21%
RTSR - Line and Transformation Connection	per kW	$ 0.6740	62	$ 41.73	$ 0.6851	62	$ 42.55	$ 0.82	1.96%
Sub-Total C - Delivery (including Sub-Total B)				**$ 710.21**			**$ 766.88**	**$ 56.66**	**7.98%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	20640	$ 90.82	$ 0.0044	20703	$ 91.09	$ 0.28	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	20640	$ 24.77	$ 0.0012	20703	$ 24.84	$ 0.08	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	20000	$ 140.00	$ 0.0070	20000	$ 140.00	$ -	
Energy - Non RPP - Spot Price	per kWh	$ 0.0872	20640	$ 1,799.19	$ 0.0872	20703	$ 1,804.67	$ 5.48	0.30%
Total Bill on RPP (before Taxes)				**$ 2,765.24**			**$ 2,827.73**	**$ 62.49**	**2.26%**
HST		13%		$ 359.48	13%		$ 367.60	$ 8.12	2.26%
Total Bill (including HST)				$ 3,124.72			$ 3,195.33	$ 70.62	2.26%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 3,124.72**			**$ 3,195.33**	**$ 70.62**	**2.26%**

Loss Factor (%) — Current: 0.03200 — Proposed: 0.03514

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **GS>50kW**

Consumption	**100**	**kW**
	40000	**kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 237.7200	1	$ 237.72	$ 237.7200	1	$ 237.72	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -			$ -				
Distribution Volumetric Rate	per kW	$ 4.0593	100	$ 405.93	$ 3.9554	100	$ 395.54	-$ 10.39	-2.56%
LRAM & SSM Rate Rider	per kW	$ 0.0172	100	$ 1.72	$ 0.0172	100	$ 1.72	$ -	
Tax Change Rate Rider	per kW	-$ 0.0676	100	-$ 6.76	-$ 0.0676	100	-$ 6.76	$ -	
1576 Rate Rider		$ -	100	$ -	-$ 0.2316	100	-$ 23.16	-$ 23.16	
Sub-Total A				$ 638.61			$ 605.06	**-$ 33.55**	**-5.25%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	100	$ -	-$ 0.0756	100	-$ 7.56	-$ 7.56	
Global Adjustment Rate Rider	per kW	$ -	100	$ -	$ 1.1133	100	$ 111.33	$ 111.33	
		$ -	100	$ -	$ -	100	$ -	$ -	
Low Voltage Service Charge		$ -	100	$ -	$ -	100	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 638.61**			**$ 708.83**	**$ 70.22**	**11.00%**
RTSR - Network	per kW	$ 3.0721	103	$ 317.04	$ 3.2836	104	$ 339.90	$ 22.86	7.21%
RTSR - Line and Transformation Connection	per kW	$ 0.6740	103	$ 69.56	$ 0.6851	104	$ 70.92	$ 1.36	1.96%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,025.21**			**$ 1,119.65**	**$ 94.44**	**9.21%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	41280	$ 181.63	$ 0.0044	41406	$ 182.19	$ 0.55	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	41280	$ 49.54	$ 0.0012	41406	$ 49.69	$ 0.15	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	40000	$ 280.00	$ 0.0070	40000	$ 280.00	$ -	
Energy - Non RPP - Spot Price	per kWh	$ 0.0872	41280	$ 3,598.38	$ 0.0872	41406	$ 3,609.33	$ 10.96	0.30%
Total Bill on RPP (before Taxes)				**$ 5,135.00**			**$ 5,241.10**	**$ 106.10**	**2.07%**
HST		13%		$ 667.55	13%		$ 681.34	$ 13.79	2.07%
Total Bill (including HST)				$ 5,802.55			$ 5,922.45	$ 119.89	2.07%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 5,802.55**			**$ 5,922.45**	**$ 119.89**	**2.07%**

Loss Factor (%) — Current: 0.03200 — Proposed: 0.03514

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **GS>50kW**

Consumption **500** kW
250000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 237.7200	1	$ 237.72	$ 237.7200	1	$ 237.72	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -			$ -				
Distribution Volumetric Rate	per kW	$ 4.0593	500	$ 2,029.65	$ 3.9554	500	$ 1,977.70	-$ 51.95	-2.56%
LRAM & SSM Rate Rider	per kW	$ 0.0172	500	$ 8.60	$ 0.0172	500	$ 8.60	$ -	
Tax Change Rate Rider	per kW	-$ 0.0676	500	-$ 33.80	-$ 0.0676	500	-$ 33.80	$ -	
1576 Rate Rider		$ -	500	$ -	-$ 0.2316	500	-$ 115.80	-$ 115.80	
Sub-Total A				$ 2,242.17			$ 2,074.42	**-$ 167.75**	**-7.48%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	500	$ -	-$ 0.0756	500	-$ 37.80	-$ 37.80	
Global Adjustment Rate Rider	per kW	$ -	500	$ -	$ 1.1133	500	$ 556.65	$ 556.65	
		$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge		$ -	500	$ -	$ -	500	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,242.17**			**$ 2,593.27**	**$ 351.10**	**15.66%**
RTSR - Network	per kW	$ 3.0721	516	$ 1,585.20	$ 3.2836	518	$ 1,699.50	$ 114.29	7.21%
RTSR - Line and Transformation Connection	per kW	$ 0.6740	516	$ 347.78	$ 0.6851	518	$ 354.59	$ 6.80	1.96%
Sub-Total C - Delivery (including Sub-Total B)				**$ 4,175.16**			**$ 4,647.35**	**$ 472.20**	**11.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	258000	$ 1,135.20	$ 0.0044	258786	$ 1,138.66	$ 3.46	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	258000	$ 309.60	$ 0.0012	258786	$ 310.54	$ 0.94	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	250000	$ 1,750.00	$ 0.0070	250000	$ 1,750.00	$ -	
Energy - Non RPP - Spot Price	per kWh	$ 0.0872	258000	$ 22,489.86	$ 0.0872	258786	$ 22,558.33	$ 68.47	0.30%
Total Bill on RPP (before Taxes)				**$ 29,860.07**			**$ 30,405.14**	**$ 545.07**	**1.83%**
HST		13%		$ 3,881.81	13%		$ 3,952.67	$ 70.86	1.83%
Total Bill (including HST)				$ 33,741.88			$ 34,357.80	$ 615.93	1.83%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 33,741.88**			**$ 34,357.80**	**$ 615.93**	**1.83%**

Loss Factor (%) Current: 0.03200 Proposed: 0.03514

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **GS>50kW**

Consumption **1000** kW
400000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 237.7200	1	$ 237.72	$ 237.7200	1	$ 237.72	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -			$ -				
Distribution Volumetric Rate	per kW	$ 4.0593	1000	$ 4,059.30	$ 3.9554	1000	$ 3,955.40	-$ 103.90	-2.56%
LRAM & SSM Rate Rider	per kW	$ 0.0172	1000	$ 17.20	$ 0.0172	1000	$ 17.20	$ -	
Tax Change Rate Rider	per kW	-$ 0.0676	1000	-$ 67.60	-$ 0.0676	1000	-$ 67.60	$ -	
1576 Rate Rider		$ -	1000	$ -	-$ 0.2316	1000	-$ 231.60	-$ 231.60	
Sub-Total A				$ 4,246.62			$ 3,911.12	**-$ 335.50**	**-7.90%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	1000	$ -	-$ 0.0756	1000	-$ 75.60	-$ 75.60	
Global Adjustment Rate Rider	per kW	$ -	1000	$ -	$ 1.1133	1000	$ 1,113.30	$ 1,113.30	
		$ -	1000	$ -	$ -	1000	$ -	$ -	
Low Voltage Service Charge		$ -	1000	$ -	$ -	1000	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4,246.62**			**$ 4,948.82**	**$ 702.20**	**16.54%**
RTSR - Network	per kW	$ 3.0721	1032	$ 3,170.41	$ 3.2836	1035	$ 3,398.99	$ 228.59	7.21%
RTSR - Line and Transformation Connection	per kW	$ 0.6740	1032	$ 695.57	$ 0.6851	1035	$ 709.18	$ 13.61	1.96%
Sub-Total C - Delivery (including Sub-Total B)				**$ 8,112.60**			**$ 9,056.99**	**$ 944.39**	**11.64%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	412800	$ 1,816.32	$ 0.0044	414057	$ 1,821.85	$ 5.53	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	412800	$ 495.36	$ 0.0012	414057	$ 496.87	$ 1.51	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	400000	$ 2,800.00	$ 0.0070	400000	$ 2,800.00	$ -	
Energy - Non RPP - Spot Price	per kWh	$ 0.0872	412800	$ 35,983.78	$ 0.0872	414057	$ 36,093.33	$ 109.56	0.30%
Total Bill on RPP (before Taxes)				**$ 49,208.30**			**$ 50,269.29**	**$ 1,060.99**	**2.16%**
HST		13%		$ 6,397.08	13%		$ 6,535.01	$ 137.93	2.16%
Total Bill (including HST)				$ 55,605.38			$ 56,804.30	$ 1,198.92	2.16%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 55,605.38**			**$ 56,804.30**	**$ 1,198.92**	**2.16%**

Loss Factor (%) Current: 0.03200 Proposed: 0.03514

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **Large User**

Consumption **5250** **kW** **2650000** **kWh**

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 14,501.6100	1	$ 14,501.61	$ 14,501.6100	1	$ 14,501.61	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -			$ -				
Distribution Volumetric Rate	per kW	$ 1.3820	5250	$ 7,255.50	$ 1.6845	5250	$ 8,843.63	$ 1,588.13	21.89%
LRAM & SSM Rate Rider	per kW	$ -	5250	$ -	$ -	5250	$ -	$ -	
Tax Change Rate Rider	per kW	-$ 0.0488	5250	-$ 256.20	-$ 0.0488	5250	-$ 256.20	$ -	
1576 Rate Rider	per kW	$ -	5250	$ -	-$ 0.3615	5250	-$ 1,897.88	-$ 1,897.88	
Sub-Total A				$ 21,500.91			$ 21,191.16	**-$ 309.75**	**-1.44%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	5250	$ -	-$ 0.2364	5250	-$ 1,241.10	-$ 1,241.10	
Global Adjustment Rate Rider	per kW	$ -	5250	$ -	$ 3.5634	5250	$ 18,707.85	$ 18,707.85	
		$ -	5250	$ -		5250	$ -	$ -	
Low Voltage Service Charge		$ -	5250	$ -	$ -	5250	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21,500.91**			**$ 38,657.91**	**$ 17,157.00**	**79.80%**
RTSR - Network	per kW	$ 2.8874	5278	$ 15,239.19	$ 3.0862	5278	$ 16,288.42	$ 1,049.23	6.89%
RTSR - Line and Transformation Connection	per kW	$ 0.6335	5278	$ 3,343.50	$ 0.6440	5278	$ 3,398.92	$ 55.42	1.66%
Sub-Total C - Delivery (including Sub-Total B)				**$ 40,083.60**			**$ 58,345.25**	**$ 18,261.65**	**45.56%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2664045	$ 11,721.80	$ 0.0044	2664045	$ 11,721.80	$ -	
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2664045	$ 3,196.85	$ 0.0012	2664045	$ 3,196.85	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2650000	$ 18,550.00	$ 0.0070	2650000	$ 18,550.00	$ -	
Energy - Non RPP - Spot Price	per kWh	$ 0.0872	2664045	$ 232,224.80	$ 0.0872	2664045	$ 232,224.80	$ -	
Total Bill on RPP (before Taxes)				**$ 305,777.31**			**$ 324,038.96**	**$ 18,261.65**	**5.97%**
HST		13%		$ 39,751.05	13%		$ 42,125.06	$ 2,374.01	5.97%
Total Bill (including HST)				$ 345,528.36			$ 366,164.02	$ 20,635.66	5.97%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 345,528.36**			**$ 366,164.02**	**$ 20,635.66**	**5.97%**

Loss Factor (%) 0.00530 (Current) 0.00530 (Proposed)

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption **37** **kW** / **750** **kWh** — (●) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 0.8000	1	$ 0.80	$ 0.8000	1	$ 0.80	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -			$ -				
Distribution Volumetric Rate	per kW	$ 5.3386	37	$ 197.53	$ 3.8405	37	$ 142.10	-$ 55.43	-28.06%
LRAM & SSM Rate Rider	per kW	$ -	37	$ -	$ -	37	$ -	$ -	
Tax Change Rate Rider	per kW	-$ 0.1278	37	-$ 4.73	-$ 0.1278	37	-$ 4.73	$ -	
1576 Rate Rider	per kW	$ -	37	$ -	-$ 0.4350	37	-$ 16.10	-$ 16.10	
Sub-Total A				$ 193.60			$ 122.07	**-$ 71.52**	**-36.94%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	37	$ -	-$ 0.1568	37	-$ 5.80	-$ 5.80	
Global Adjustment Rate Rider	per kW	$ -	37	$ -	$ 1.1630	37	$ 43.03	$ 43.03	
	per kW	$ -	37	$ -		37	$ -	$ -	
Low Voltage Service Charge		$ -	37	$ -	$ -	37	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 193.60**			**$ 159.30**	**-$ 34.30**	**-17.71%**
RTSR - Network	per kW	$ 1.8681	38	$ 71.33	$ 1.9967	38	$ 76.47	$ 5.14	7.21%
RTSR - Line and Transformation Connection	per kW	$ 0.4101	38	$ 15.66	$ 0.4169	38	$ 15.97	$ 0.31	1.97%
Sub-Total C - Delivery (including Sub-Total B)				**$ 280.59**			**$ 251.75**	**-$ 28.84**	**-10.28%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	774	$ 3.41	$ 0.0044	776	$ 3.42	$ 0.01	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	774	$ 0.93	$ 0.0012	776	$ 0.93	$ 0.00	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	750	$ 5.25	$ 0.0070	750	$ 5.25	$ -	
Energy - Non RPP - Spot Price	per kWh	$ 0.0872	774	$ 67.47	$ 0.0872	776	$ 67.67	$ 0.21	0.30%
Total Bill on RPP (before Taxes)				**$ 357.89**			**$ 329.27**	**-$ 28.63**	**-8.00%**
HST		13%		$ 46.53	13%		$ 42.80	-$ 3.72	-8.00%
Total Bill (including HST)				$ 404.42			$ 372.07	-$ 32.35	-8.00%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 404.42**			**$ 372.07**	**-$ 32.35**	**-8.00%**

Loss Factor (%) — Current: 0.03200 — Proposed: 0.03514

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption **2000** **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 8.5200	1	$ 8.52	$ 8.5200	1	$ 8.52	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -	1	$ -	$ -	1	$ -	$ -	
		$ -			$ -				
Distribution Volumetric Rate	per kWh	$ 0.0124	2000	$ 24.80	$ 0.0061	2000	$ 12.20	-$ 12.60	-50.81%
LRAM & SSM Rate Rider	per kWh	$ 0.0045	2000	$ 9.00	$ 0.0045	2000	$ 9.00	$ -	
Tax Change Rate Rider	per kWh	-$ 0.0005	2000	-$ 1.00	-$ 0.0005	2000	-$ 1.00	$ -	
1576 Rate Rider	per kWh	$ -	2000	$ -	-$ 0.0019	2000	-$ 3.80	-$ 3.80	
Sub-Total A				$ 41.32			$ 24.92	**-$ 16.40**	**-39.69%**
Deferral/Variance Account Disposition Rate	per kWh	$ -	2000	$ -	-$ 0.0008	2000	-$ 1.60	-$ 1.60	
		$ -	2000	$ -	$ -	2000	$ -	$ -	
		$ -	2000	$ -	$ -	2000	$ -	$ -	
Low Voltage Service Charge		$ -	2000	$ -	$ -	2000	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 41.32**			**$ 23.32**	**-$ 18.00**	**-43.56%**
RTSR - Network	per kWh	$ 0.0058	2064	$ 11.97	$ 0.0062	2070	$ 12.84	$ 0.86	7.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	2064	$ 2.68	$ 0.0013	2070	$ 2.69	$ 0.01	0.30%
Sub-Total C - Delivery (including Sub-Total B)				**$ 55.97**			**$ 38.85**	**-$ 17.13**	**-30.60%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2064	$ 9.08	$ 0.0044	2070	$ 9.11	$ 0.03	0.30%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2064	$ 2.48	$ 0.0012	2070	$ 2.48	$ 0.01	0.30%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2070	$ 14.49	$ 0.49	3.51%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0910	1464	$ 133.22	$ 0.0910	1470	$ 133.80	$ 0.57	0.43%
TOU - Off Peak	per kWh	$ 0.0670	1321	$ 88.50	$ 0.0670	1325	$ 88.77	$ 0.27	0.30%
TOU - Mid Peak	per kWh	$ 0.1040	372	$ 38.64	$ 0.1040	373	$ 38.76	$ 0.12	0.30%
TOU - On Peak	per kWh	$ 0.1240	372	$ 46.07	$ 0.1240	373	$ 46.21	$ 0.14	0.30%
Total Bill on RPP (before Taxes)				**$ 261.81**			**$ 245.78**	**-$ 16.03**	**-6.12%**
HST		13%		$ 34.03	13%		$ 31.95	-$ 2.08	-6.12%
Total Bill (including HST)				$ 295.84			$ 277.73	-$ 18.11	-6.12%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 295.84**			**$ 277.73**	**-$ 18.11**	**-6.12%**
Total Bill on TOU (before Taxes)				**$ 254.99**			**$ 238.92**	**-$ 16.07**	**-6.30%**
HST		13%		$ 33.15	13%		$ 31.06	-$ 2.09	-6.30%
Total Bill (including HST)				$ 288.14			$ 269.98	-$ 18.16	-6.30%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 288.14**			**$ 269.98**	**-$ 18.16**	**-6.30%**
Loss Factor (%)		0.03200			0.03514				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

c) Please provide a revised Table 8-18 based upon the above approach and the updated August 9 material.

Answer: See table below:

Table 8-18

Summary of Bill Impacts					
Rate Class	Consumption kWh	Delivery		Total Bill	
		Difference ($)	Difference (%)	Difference ($)	Difference (%)
Residential RPP	100	$ 2.59	19.58%	$ 2.72	11.30%
Residential TOU	100	$ 2.59	19.58%	$ 2.72	11.03%
Residential RPP	250	$ 1.66	10.50%	$ 1.89	4.49%
Residential TOU	250	$ 1.66	10.50%	$ 1.90	4.34%
Residential RPP	500	$ 0.11	0.55%	$ 0.52	0.72%
Residential TOU	500	$ 0.11	0.55%	$ 0.53	0.70%
Residential RPP	800	-$ 1.75	-6.93%	-$ 1.09	-0.98%
Residential TOU	800	-$ 1.75	-6.93%	-$ 1.11	-0.98%
Residential RPP	1000	-$ 2.99	-10.41%	-$ 2.18	-1.58%
Residential TOU	1000	-$ 2.99	-10.41%	-$ 2.20	-1.58%
Residential RPP	1500	-$ 6.09	-16.32%	-$ 4.91	-2.38%
Residential TOU	1500	-$ 6.09	-16.32%	-$ 4.93	-2.44%
Residential RPP	2000	-$ 9.19	-20.02%	-$ 7.62	-2.79%
Residential TOU	2000	-$ 9.19	-20.02%	-$ 7.66	-2.88%
General Service < 50 kW RPP	1000	$ 1.97	3.80%	$ 3.00	1.86%
General Service < 50 kW TOU	1000	$ 1.97	3.80%	$ 2.99	1.85%
General Service < 50 kW RPP	2000	$ 1.07	1.67%	$ 3.10	1.07%
General Service < 50 kW TOU	2000	$ 1.07	1.67%	$ 3.06	1.08%
General Service < 50 kW RPP	5000	-$ 1.63	-1.62%	$ 3.73	0.50%
General Service < 50 kW TOU	5000	-$ 1.63	-1.62%	$ 3.60	0.50%
General Service < 50 kW RPP	10000	-$ 6.13	-3.79%	$ 4.21	0.29%
General Service < 50 kW TOU	10000	-$ 6.13	-3.79%	$ 3.96	0.29%
General Service < 50 kW RPP	15000	-$ 10.63	-4.77%	$ 4.70	0.22%
General Service < 50 kW TOU	15000	-$ 10.63	-4.77%	$ 4.32	0.21%
General Service > 50 kW RPP	20000	$ 42.13	8.81%	$ 70.62	2.26%
General Service > 50 kW RPP	40000	$ 70.22	11.00%	$ 119.89	2.07%
General Service > 50 kW RPP	250000	$ 351.10	15.66%	$ 615.93	1.83%
General Service > 50 kW RPP	400000	$ 702.20	16.54%	$ 1,198.92	2.16%
Large User	2650000	$ 17,157.00	79.80%	$ 20,635.66	5.97%
Unmetered Loads RPP	2000	-$ 18.00	-43.56%	-$ 18.11	-6.12%
Unmetered Loads TOU	2000	-$ 18.00	-43.56%	-$ 18.16	-6.30%
Street Lighting	750	-$ 34.30	-17.71%	-$ 32.35	-8.00%

End of Energy Probe Exhibit Seven Interrogatories

No School Energy Coalition Exhibit Seven Interrogatories

VECC Exhibit Seven Interrogatories

7.0-VECC – 32

Reference: Exhibit 7, Tab 1, Schedule 1, pages 2-4

a) Please explain why the Billing & Collecting weighting factor for GS<50 is 0.80 – less than that for Residential.

Answer: GS<50 has a weighting that is less than a residential customer. These customers have less billing inquiries and less collection activity than a residential customer; therefore this necessitates the lower weighting.

b) Please explain why there is no weighting factor assigned to the Embedded Distributor for Billing & Collecting.

Answer: The direct allocation method was used for this class so these were set to zero.

c) Please explain why there is no Meter Capital cost assigned to the Embedded Distributor.

Answer: The direct allocation method was used for this class so these were set to zero.

d) Please explain why there is no Meter Reading cost assigned to the Embedded Distributor.

Answer: The direct allocation method was used so these were set to zero. There is no cost for the meter for the embedded customer as the meter belongs to the embedded distributor.

7.0-VECC – 33

Reference: Exhibit 7, Tab 1, Schedule 1, pages 5-7

a) Please confirm that directly allocated asset costs are not included in the allocation factor used in the Board's CA Model to assign General Plant (i.e., generally the 1900 series accounts) costs. This can be seen from an examination of Sheet O5.

Answer: Confirmed

b) Please confirm that Kitchener has not included the capital cost of any General Plant in its direct allocation (per Table 7-6).

Answer: Confirmed

c) Is it Kitchener's view that the Embedded Distributor should not be accountable for a share of any of the General Plant costs? If yes, please list the individual accounts and provide an explanation for each.

Answer: KWHI used Appendix 2-Q as a basis for allocating costs to the Embedded Distributor. In Appendix 2-Q, costs are allocated based on Capital assets and OM & A costs.

d) Please confirm that directly allocated expenses are not included in the allocation factor used in the Board's CA model to allocate Administrative and General Expenses (i.e. generally the 5600 series accounts). This can also be seen by inspecting Sheet O5.

Answer: Confirmed

e) Is it Kitchener's view that the Embedded Distributor should not be accountable for a share of any of the other Administrative and General Costs? If yes, please list the individual accounts and provide an explanation for each.

Answer: KWHI has taken the amount of administration calculated on Appendix 2-Q and directly allocated it to administrative costs in the Cost Allocation Model sheet I9. These administration costs should cover both general plant costs as well as administration and general costs.

f) Please explain how the direct allocation was established for each of the items listed in Tables 7-6 and 7-7.

Answer: The direct allocation for each item was established as per Appendix 2-Q and using the formulas in that Appendix.

The formula was applied to the asset values and the Operating and Maintenance costs for those assets. The same percentage was applied to the depreciation expense of the assets employed by the embedded distributor.

g) Please calculate revised allocators for General Plant and Administrative & General Expenses that include the relevant costs directly assigned to the Embedded Distributor.

Answer: Using Appendix 2-Q, administration costs to cover the general plant and administration costs is calculated using KWHI's standard rate of 9%.

h) Using these allocators from part (g) what dollars from each cost category should be assigned to the Embedded Distributor?

Answer: In total, $7,433 was allocated to the Embedded Distributor to cover the general plant and administration costs using OEB account 5615.

i) Please re-do the cost allocation directly assigning to the Embedded Distributor the General Plant and Administrative & General Expenses identified above.

Answer: See below:

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	6	7	9	10
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Unmetered Scattered Load	Embedded Distributor
crev	Distribution Revenue at Existing Rates	$38,207,936	$20,949,749	$5,411,737	$10,926,313	$223,287	$477,296	$147,719	$71,836
mi	Miscellaneous Revenue (mi)	$2,039,200	1,476,309	229,693	307,106	4,012	16,335	5,745	$0
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$40,247,136	$22,426,057	$5,641,430	$11,233,419	$227,299	$493,631	$153,464	$71,836
	Factor required to recover deficiency (1 + D)	0.9792							
	Distribution Revenue at Status Quo Rates	$37,414,666	$20,514,792.00	$5,299,378.53	$10,699,461.70	$218,651.02	$467,386.32	$144,651.99	$70,344
	Miscellaneous Revenue (mi)	$2,039,200	$1,476,309	$229,693	$307,106	$4,012	$16,335	$5,745	$0
	Total Revenue at Status Quo Rates	$39,453,866	$21,991,101	$5,529,072	$11,006,568	$222,663	$483,721	$150,397	$70,344
	Expenses								
di	Distribution Costs (di)	$10,516,658	$5,948,020	$1,319,455	$3,020,366	$78,954	$114,478	$35,385	$0
cu	Customer Related Costs (cu)	$4,654,100	$3,888,155	$460,004	$303,811	$1,279	$448	$404	$0
ad	General and Administration (ad)	$3,715,367	$2,330,580	$450,223	$873,533	$21,420	$30,493	$9,117	$0
dep	Depreciation and Amortization (dep)	$7,544,264	$4,129,583	$1,111,894	$2,156,443	$54,205	$73,240	$18,899	$0
INPUT	PILs (INPUT)	$432,645	$231,571	$59,394	$132,532	$3,458	$4,552	$1,138	$0
INT	Interest	$5,011,509	$2,682,388	$687,984	$1,535,173	$40,050	$52,730	$13,185	$0
	Total Expenses	$31,874,543	$19,210,297	$4,088,953	$8,021,858	$199,365	$275,941	$78,128	$0
	Direct Allocation	$70,870	$0	$0	$0	$0	$0	$0	$70,870
NI	Allocated Net Income (NI)	$7,508,453	$4,018,866	$1,030,767	$2,300,060	$60,005	$79,002	$19,754	$0
	Revenue Requirement (includes NI)	$39,453,866	$23,229,163.1	$5,119,720.2	$10,321,917.5	$259,370.1	$354,943.1	$97,881.7	$70,870.2
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$343,080,438	$192,893,388	$45,865,787	$97,086,574	$2,385,383	$3,792,002	$1,057,303	$0
gp	General Plant - Gross	$42,327,121	$23,645,798	$5,702,137	$12,094,201	$303,250	$454,228	$127,506	$0
accum dep	Accumulated Depreciation	($147,445,600)	($82,028,260)	($19,650,832)	($42,595,903)	($1,040,411)	($1,687,117)	($443,077)	$0
co	Capital Contribution	($55,578,366)	($36,424,099)	($6,930,488)	($11,126,360)	($207,187)	($635,946)	($254,287)	$0
	Total Net Plant	$182,383,592	$98,086,827	$24,986,603	$55,458,513	$1,441,036	$1,923,167	$487,447	$0
	Directly Allocated Net Fixed Assets	$539,708	$0	$0	$0	$0	$0	$0	$539,708
COP	Cost of Power (COP)	$184,456,631	$67,113,123	$24,873,246	$85,091,778	$3,273,573	$1,660,358	$351,785	$2,092,767
	OM&A Expenses	$18,886,125	$12,166,755	$2,229,682	$4,197,710	$101,653	$145,419	$44,906	$0
	Directly Allocated Expenses	$31,875	$0	$0	$0	$0	$0	$0	$31,875
	Subtotal	*$203,374,631*	*$79,279,878*	*$27,102,928*	*$89,289,488*	*$3,375,226*	*$1,805,778*	*$396,691*	*$2,124,642*
	Working Capital	$26,438,702	$10,306,384	$3,523,381	$11,607,633	$438,779	$234,751	$51,570	$276,204
	Total Rate Base	$209,362,002	$108,393,211	$28,509,984	$67,066,147	$1,879,815	$2,157,918	$539,017	$815,912
		Rate Base Input equals Output							
	Equity Component of Rate Base	$83,744,801	$43,357,284	$11,403,993	$26,826,459	$751,926	$863,167	$215,607	$326,365
	Net Income on Allocated Assets	$7,509,944	$2,780,803	$1,440,118	$2,984,710	$23,298	$207,780	$72,270	$966
	Net Income on Direct Allocation Assets	$11,830	$0	$0	$0	$0	$0	$0	$11,830
	Net Income	$7,521,774	$2,780,803	$1,440,118	$2,984,710	$23,298	$207,780	$72,270	$12,796
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	94.67%	108.00%	106.63%	85.85%	136.28%	153.65%	99.26%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$793,270	($803,106)	$521,710	$911,501	($32,071)	$138,688	$55,583	$966
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($1,238,063)	$409,352	$684,650	($36,707)	$128,778	$52,516	($526)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	6.41%	12.63%	11.13%	3.10%	24.07%	33.52%	3.92%

2013 Cost Allocation Model

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary	1	2	3	6	7	9	10
	Residential	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Embedded Distributor**
Customer Unit Cost per month - Avoided Cost	$4.37	$9.02	$32.03	$84.38	-$0.03	-$0.03	0
Customer Unit Cost per month - Directly Related	$5.35	$10.80	$40.02	$117.66	-$0.02	-$0.02	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$12.52	$19.76	$72.84	$123.32	$4.94	$5.20	0
Existing Approved Fixed Charge	$9.76	$25.71	$237.72	$14,501.61	$0.80	$8.52	$0.00

7.0-VECC – 34
Reference: Exhibit 7, Tab 1

a) As required, please update the Tables in Exhibit 7, Tab 1 to reflect the results of the revised Cost Allocation Model run filed on August 9, 2013.

Answer: Tables 7-1 – Table 7-4 do not change with the updated information as filed August 9th. Table 7-5 may change, but is not presented here.

Tables 7-6 through to 7-8 deal with the embedded distributor and there was no change in the allocation of costs to the embedded distributor in the updated August 9th filing.

Revised Tables 7-9 to 7-11 are presented below:

Table 7-9

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study	%
Residential	23,233,322	58.39%	23,233,982	58.89%
GS < 50 kW	5,145,303	12.93%	5,120,592	12.98%
GS > 50 kW	10,328,798	25.96%	10,323,546	26.17%
Large User	570,358	1.43%	259,409	0.66%
Street Lighting	394,205	0.99%	354,999	0.90%
Unmetered Scattered Load	115,338	0.29%	97,899	0.25%
Embedded distributor class		0.00%	63,437	0.16%
Total	39,787,324	100.00%	39,453,864	100.00%

Table 7-10

Classes	2010 COS Application	2014 COS Study - Default	2014 COS Study - Proposed	Board Targets	
				Min	Max
Residential	91.13	94.65	99.61	85.00%	115.00%
GS < 50 kW	104.60	107.98	100.00	80.00%	120.00%
GS > 50 kW	116.90	106.62	100.00	80.00%	120.00%
Large User, if applicable	96.00	85.84	100.00	85.00%	115.00%
Street Lighting	120.00	136.26	120.00	70.00%	120.00%
Unmetered Scattered Load (USL)	120.00	153.62	120.00	80.00%	120.00%
Embedded distributor class		110.89	100.00		

Table 7-11

Class	2014 Base Revenue at existing Rates	2014 Proposed Base Revenue allocated at existing rates	2014 Proposed Base Revenue	Miscellaneous Revenue
Residential	$ 20,949,749	$ 20,514,793	$ 21,667,099	$ 1,439,237
GS < 50 kW	$ 5,411,737	$ 5,299,379	$ 4,890,898	$ 215,142
GS > 50 kW	$ 11,558,203	$ 10,699,462	$ 10,016,438	$ 359,881
Large User, if applicable	$ 261,088	$ 218,651	$ 255,397	$ 3,988
Street Lighting	$ 477,297	$ 467,388	$ 409,664	$ 15,183
Unmetered Scattered Load (USL)	$ 147,719	$ 144,652	$ 111,734	$ 5,769
Embedded distributor class	$ 71,835	$ 70,344	$ 63,438	$ -
Total	**$ 38,877,628**	**$ 37,414,668**	**$ 37,414,668**	**$ 2,039,200**

7.0-VECC – 35

Reference: Exhibit 7, Tab 1, Schedule 1, page 10

a) *Please confirm that the load profiles used in the cost allocation are based on 2004 data from Hydro One. If not, what is the basis for the load profiles?*

Answer: Confirmed.

b) *Given the current status of the load profiles used, why is it appropriate to move the revenue to cost ratios for the two GS classes and the Large User class to 100%?*

Answer: KWHI believes that it is always better to endeavour to reduce any cross subsidization between rate classes. KWHI notes an excerpt from Board direction as per Guideline EB – 2007-0667:

"The Board expects to address these concerns as and when they arise in the context of individual rate applications. Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one."

End of Exhibit Seven Interrogatories

Board Staff Exhibit Eight Interrogatories

Exhibit 8 – Rate Design

8-Staff-35 Ref: Exhibit 8/Tab 1/Schedule 1 – Fixed/Variable Split and Proposed Rates

Below Table 8-5, KWHI states: "Consistent with recent Board Decisions on Cost of Service Applications, KWHI is proposing to maintain the current fixed/variable proportions for all rate classes except for Residential"

Two pages later, above Table 8-8, KWHI states: "This application proposes to adjust the fixed/variable split on rate classes where this is permitted. The proposed Fixed/Variable split is presented in Table 8-8 below."

Tables 8-5 and 8-8 show different fixed (revenue) ratios.

In response to the Board's letter of August 1, 2013 requesting additional information per the Filing Requirements for Transmission and Distribution Applications issued July 17, 2013, KWHI filed updated evidence, including an updated Cost Allocation model and proposed rates on August 9 and 13, 2013.

Answer: Table 8-5 is using 2013 rates based on 2014 volumes. Table 8-8 is using proposed 2014 rates at 2014 volumes. Because the split is changing in the Residential Class, the fixed revenue ratios will change for all classes using 2014 rates.

a) If necessary, provide updates to applicable Tables in Exhibit 8 to correspond with the updated evidence filed on August 9 and 13, 2013.

Answer: Table 8-1 (Revised for August 9th and 13th filing)

Table 8-1

OM&A Expenses		18,918,000
Amortization Expenses		7,562,853
Total Distribution Expenses		**26,480,853**
Regulated Return On Capital		12,539,688
PILs		433,327
Service Revenue Requirement		**39,453,868**
Less: Revenue Offsets		2,039,200
Base Revenue Requirement		**37,414,668**
Transformer Discounts		669,692
Gross Revenue Required for Rates	**$**	**38,084,360**

Table 8-3 (Revised for August 9th and 13th filing)

Table 8-3

Customer Class	2014 Distribution Revenue before Transformer Ownership Allowance at Existing Rates	Proposed Revenue to Cost Ratio	Proposed Cost Allocation Revenue Adjustments	2014 Cost Allocation Adjusted Revenues	%
Residential	20,514,793	99.6%	1,152,306	21,667,099	57.91%
GS <50 kW	5,299,379	100.0%	-408,481	4,890,898	13.07%
GS >50 kW	10,699,462	100.0%	-683,024	10,016,438	26.77%
Large Use	218,652	100.0%	36,745	255,397	0.68%
Street Lighting	467,386	120.0%	-57,722	409,664	1.09%
Unmetered Scattered Load	144,652	120.0%	-32,918	111,734	0.30%
Embedded Distributor	70,344	0.0%	-6,906	63,438	0.17%
	37,414,668		**0**	**37,414,668**	**100.00%**

Table 8-6 (Revised for August 9th and 13th filing)

Table 8-6

	2013 Approved Monthly Service Charge	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per Month Minimum System with PLCC Adjustment
Residential	9.76	4.37	12.53
GS <50 kW	25.71	9.02	19.76
GS >50 kW	237.72	32.03	72.86
Large Use	14,501.61	84.38	123.37
Street Lighting	0.80	(0.03)	4.94
Unmetered Scattered Load	8.52	(0.03)	5.20
Embedded Distributor			

Table 8-7

	Fixed Monthly Service Charge
	Residential
Kitchener- Wilmot Hydro (Proposed)	12.53
Cambridge and North Dumfries Hydro*	10.09
Guelph Hydro	14.10
London Hydro	13.12
Waterloo North Hydro	14.79

*** CNDHI is submitting cost of service application for 2014.**

b) Please confirm whether KWHI is maintaining existing F/V ratios or changing them. Please explain the rationale for KWHI's proposal.

Answer: KWHI in its original evidence said it was proposing to maintain the current F/V split for all classes except Residential. However, what KWHI meant to say is that it was keeping all of the Monthly Service Charges for all customer classes the same except for the Residential. The Current and Proposed splits are presented below:

Customer Class	Current Volumetric Split	Current Fixed Charge Split	Total
Residential	53.84%	46.16%	100.00%
GS <50 kW	55.36%	44.64%	100.00%
GS >50 kW	75.33%	24.67%	100.00%
Large Use	22.06%	77.94%	100.00%
Street Lighting	50.50%	49.50%	100.00%
Unmetered Scattered Load	38.40%	61.60%	100.00%
Embedded Distributor	100.00%	0.00%	100.00%
TOTAL			

Customer Class	Proposed Volumetric Split	Proposed Fixed Charge Split	Total
Residential	57.30%	42.70%	100.00%
GS <50 kW	49.39%	50.61%	100.00%
GS >50 kW	25.32%	74.68%	100.00%
Large Use	59.35%	40.65%	100.00%
Street Lighting	57.68%	42.32%	100.00%
Unmetered Scattered Load	81.44%	18.56%	100.00%
Embedded Distributor	0.00%	100.00%	100.00%
TOTAL			

Existing 2013 Rate Year - Distribution Revenue Rates

	Fixed Charges		Volumetric Charges	
Customer Class	**Connection**	**Customer**	**kW**	**kWh**
Residential		9.76		0.0173
GS <50 kW		25.71		0.0124
GS >50 kW		237.72	4.0593	
Large Use		14,501.61	1.3820	
Street Lighting	0.80		5.3386	
Unmetered Scattered Load	8.52			0.0166
Embedded Distributor - Dedicated			1.4660	
Embedded Distributor - Shared			0.1420	

Proposed 2014 Rate Year - Distribution Revenue Rates

	Fixed Charges		Volumetric Charges	
Customer Class	**Connection**	**Customer**	**kW**	**kWh**
Residential		12.53		0.0142
GS <50 kW		25.71		0.0102
GS >50 kW		237.72	3.6425	
Large Use		14,501.61	1.8917	
Street Lighting	0.80		3.8405	
Unmetered Scattered Load	8.52			0.0061
Embedded Distributor			1.4200	

8-Staff-36 Ref: Exhibit 8/Tab 2/Schedule 1/p. 2 – Retail Transmission Service Rates

KWHI is proposing to increase its RTSRs by 7% (Network) and 2% (Connection), observing that there has been a gap between wholesale cost and RTSR revenue in recent years.

Please provide year-to-date amounts and projected 2013 year-end amounts for Accounts 4066, 4068, 4714 and 4716.

Answer: See the table below with actuals as of August 2013. Note the projection to year end is simply an extrapolation of the figures to the end of the year.

Account Description	August 2013 YTD	Projected 2013
Network Billed to Customers	8,862,797	13,294,196
Network Transmission Charges	(9,082,285)	(13,623,428)
Variance	(219,488)	(329,233)
Connection Billed to Customers	2,019,660	3,029,490
Transmission Connection Chgs	(1,953,440)	(2,930,159)
Variance	66,220	99,331

8-Staff-37 Ref: Exhibit 8/Tab 2/Schedule 1 and Attachment 1 – Retail Transmission Service Rates

In light of the timing of its filing of its Application, KWHI noted that there was no 2014 Retail Transmission Service Rates ("RTSR") model available, and filed a copy of the 2013 RTSR model approved in its 2013 IRM application EB-2012-0143.

A 2014 RTSR model was issued on July 17, 2013 as part of the updated Filing Requirements for Transmission and Distribution Applications. The model is available on the Board's website at *http://www.ontarioenergyboard.ca/OEB/_Documents/2014EDR/2014%20RTSR%20MODEL_V4.0_20130715.xlsm* .

Please file an updated 2014 RTSR model and update Exhibit 8/Tab 2/Schedule 1, as necessary.

Answer: RTSR Model Attached as Appendix E.

Table 8-11

		2013	Adjusted Rates Proposed 2014
Network	Residential	0.0067	0.0067
	GS <50 kW	0.0058	0.0058
	GS >50 kW	3.0721	3.0729
	Large Use	2.8874	2.8881
	Street Lighting	1.8681	1.8686
	Unmetered Scattered Load	0.0058	0.0058
	Embedded Distributor	2.8965	2.8972
Connection	Residential	0.0014	0.0014
	GS <50 kW	0.0013	0.0013
	GS >50 kW	0.6740	0.6638
	Large Use	0.6335	0.6239
	Street Lighting	0.4101	0.4039
	Unmetered Scattered Load	0.0013	0.0013
	Embedded Distributor	0.6356	0.6260

8-Staff-38 Ref: Exhibit 8/Tab 3/Schedule 1/Attachment 1, Appendix 2-V, Revenue Requirement Work Form/Tab "Rev_Reqt" – Distribution Rate Revenue

The RRWF and Appendix 2-V show 2014 distribution rate revenue of $37,414,668, whereas Table 8-17 shows rate revenue (after Transformer Ownership Allowance) of $35,259,622. Please explain which of these numbers is correct, and if necessary please recalculate the proposed distribution rates.

Answer: The $35,259,622 is from June 21st and was updated in August 2013. Table 8-17 was not re-filed in August 13. Also, Table 8-17 as filed on June 21 is incorrect as it removes the transformer allowance, when it should be added. As filed in August 2013, the revenue requirement was:

Service Revenue Requirement	**$**	**39,453,868**
Less: Revenue Offsets	**$**	**2,039,200**
Total Base Revenue Requirement	**$**	**37,414,668**
Addback Transformer Allowances	**$**	**669,692**
Gross Revenues For Rates	**$**	**38,084,360**

Table 8-17 should be re-filed as:

Table 8-17

Class	2014 Projected Distribution Revenue at Existing Rates								
	Fixed Revenue			Variable Revenue			Total Revenue		
	Fixed Rate	Customer / Connections	Fixed Revenue	Variable Rate	KW / kWh	Variable Charge Revenue	Totals	Transformer Ownership Allowance	Totals Transformer Ownership Credit
Residential	12.53	82,577	$ 12,416,278	0.0142	651,926,620	9,250,821	**$ 21,667,099**		**$ 21,667,099**
GS <50 kW	25.71	7,830	$ 2,415,712	0.0102	241,614,912	2,475,186	**$ 4,890,898**		**$ 4,890,898**
GS >50 kW	237.72	945	$ 2,695,745	3.6425	2,183,248	7,320,693	**$ 10,016,438**	$ 631,891	**$ 10,648,329**
Large Use	14,501.61	1	$ 174,019	1.8917	63,002	81,378	**$ 255,397**	$ 37,801	**$ 293,198**
Street Lighting	0.80	24,613	$ 236,285	3.8405	45,145	173,379	**$ 409,664**		**$ 409,664**
Unmetered Scattered Load	8.52	890	$ 90,994	0.0061	3,417,188	20,740	**$ 111,734**		**$ 111,734**
Embedded Distributor	-		$ -	1.4200	44,674	63,438	**$ 63,438**		**$ 63,438**
Totals	**14,786.89**		**$ 18,029,032**			**$ 19,385,636**	**$ 37,414,668**	**$ 669,692**	**$ 38,084,360**

8-Staff-39 Ref: Exhibit 8/Tab 1/Schedule 1/p. 4, Exhibit 8/Tab 3/Schedule 3/Attachment 1, Cost Allocation Model/Sheet O-2 – Residential Monthly Service Charge

The proposed tariff sheet and the Bill Impact sheet in Attachment 1 show a proposed Monthly Service Charge of $11.72, and a Distribution (sub-total B) bill impact of 15.72%. In contrast, Appendix 2-W shows a proposed charge of $12.53 and an impact of 20.83%. This charge appears to be consistent with the cost allocation model and the statement at Exhibit 8-1-1, top of p. 4. Please clarify which charge KWHI is proposing for the Residential class.

Answer: As filed on June 21, the proposed residential Service charge was $11.72. As a result of removing 1576, information was re-filed on August 13th, proposing a Monthly Service

Charge for the Residential class of $12.53. This is consistent with the statement on E8T1S1 pg 4.

End of Board Staff Exhibit Eight Interrogatories

Energy Probe Exhibit Eight Interrogatories

8-Energy Probe-57

Ref: Exhibit 8, Tab 1, Schedule 1 &
August 9 Material

a) What would be the proposed fixed charge for the Residential class if KWHI maintained the current fixed/variable proportions for this rate class?

Answer: $10.09

b) Please add a column to Table 8-7 that shows the current fixed proportion of revenues for the Residential class from the distributors shown in Table 8-7, as referenced in the paragraph immediately preceding the table.

Answer: It is assumed this question follows from a). That if KWHI keeps the current fixed/variable proportions as in part a) above.

Table 8-7

	Fixed Monthly Service Charge	Fixed Monthly Service Charge
	Residential	Residential
Kitchener- Wilmot Hydro	10.09	46.2%
Cambridge and North Dumfries Hydro	10.09	44.9%
Guelph Hydro	14.10	55.5%
London Hydro	13.12	56.0%
Waterloo North Hydro	14.79	50.9%

c) Please provide a revised Table 8-18 (Exhibit 8, Tab 3, Schedule 3) that reflects a Residential fixed charge based on maintaining the fixed/variable split as requested in part (a) above and the August 9 material for the overall sufficiency.

Answer: Maintaining the fixed /variable split as per part a) above, and maintaining the fixed charge for the other customers as proposed in the Cost of Service.

Table 8-18

Summary of Bill Impacts					
Rate Class	Consumption kWh	Delivery		Total Bill	
		Difference ($)	Difference (%)	Difference ($)	Difference (%)
Residential RPP	100	$ 0.69	5.22%	$ 0.78	3.25%
Residential TOU	100	$ 0.69	5.22%	$ 0.78	3.17%
Residential RPP	250	$ 0.57	3.61%	$ 0.79	1.88%
Residential TOU	250	$ 0.57	3.61%	$ 0.79	1.80%
Residential RPP	500	$ 0.37	1.84%	$ 0.78	1.08%
Residential TOU	500	$ 0.37	1.84%	$ 0.79	1.05%
Residential RPP	800	$ 0.13	0.51%	$ 0.82	0.74%
Residential TOU	800	$ 0.13	0.51%	$ 0.80	0.71%
Residential RPP	1000	-$ 0.03	-0.10%	$ 0.83	0.60%
Residential TOU	1000	-$ 0.03	-0.10%	$ 0.81	0.58%
Residential RPP	1500	-$ 0.43	-1.15%	$ 0.85	0.41%
Residential TOU	1500	-$ 0.43	-1.15%	$ 0.82	0.41%
Residential RPP	2000	-$ 0.83	-1.81%	$ 0.89	0.32%
Residential TOU	2000	-$ 0.83	-1.81%	$ 0.84	0.31%
General Service < 50 kW RPP	1000	$ 0.27	0.52%	$ 1.27	0.79%
General Service < 50 kW TOU	1000	$ 0.27	0.52%	$ 1.25	0.78%
General Service < 50 kW RPP	2000	-$ 2.33	-3.64%	-$ 0.36	-0.13%
General Service < 50 kW TOU	2000	-$ 2.33	-3.64%	-$ 0.41	-0.14%
General Service < 50 kW RPP	5000	-$ 10.13	-10.06%	-$ 5.88	-0.78%
General Service < 50 kW TOU	5000	-$ 10.13	-10.06%	-$ 6.00	-0.84%
General Service < 50 kW RPP	10000	-$ 23.13	-14.31%	-$ 15.00	-1.03%
General Service < 50 kW TOU	10000	-$ 23.13	-14.31%	-$ 15.25	-1.10%
General Service < 50 kW RPP	15000	-$ 36.13	-16.23%	-$ 24.12	-1.11%
General Service < 50 kW TOU	15000	-$ 36.13	-16.23%	-$ 24.49	-1.19%
General Service > 50 kW RPP	20000	$ 23.36	4.88%	$ 49.40	1.58%
General Service > 50 kW RPP	40000	$ 38.93	6.10%	$ 84.53	1.46%
General Service > 50 kW RPP	250000	$ 194.65	8.68%	$ 439.14	1.30%
General Service > 50 kW RPP	400000	$ 389.30	9.17%	$ 845.34	1.52%
Large User	2650000	$ 18,244.80	84.86%	$ 21,864.88	6.33%
Unmetered Loads RPP	2000	-$ 18.00	-43.56%	-$ 18.11	-6.12%
Unmetered Loads TOU	2000	-$ 18.00	-43.56%	-$ 18.16	-6.30%
Street Lighting	750	-$ 34.30	-17.71%	-$ 32.35	-8.00%

8-Energy Probe-58

Ref: Exhibit 8, Tab 2, Schedule 7

Please explain how the transformer ownership credit works for the Large Use class when there is only one customer forecast to be in that class in 2014. In particular, does this remaining customer provide its own equipment? If yes, please explain why a credit is needed if no costs are being incurred by KWHI for this customer. If no, please explain why the customer is receiving a credit.

Answer: The transformer ownership credits works the same for the Large User customers as it does for any other customer that receives the credit. The large use customer does provide its own equipment. The credit is simply a continuation of the existing rate structure as it has existed for many years.

End of Energy Probe Exhibit Eight Interrogatories

No School Energy Coalition Exhibit Eight Interrogatories

VECC Exhibit Eight Interrogatories

8.0-VECC – 36

Reference: Exhibit 8, Tab 1, Schedule 1, pages 3-4

a) For each of the Distributors listed in Table 8-7, how does the monthly service charge in their last Cost of Service application compare to the Customer Unit Cost per Month – Minimum System with PLCC Adjustment value as calculated at that time?

Answer: These numbers are as per the original filing of the distributor. Fixed charges have changed since the original cost of service filings for other IRM applications. Also, please note, that KWHI has filed updated information on August 9th changing the proposed Monthly service Charge to $12.53 and the Customer Unit Cost per Month – Minimum System with PLCC Adjustment to $12.53.

	Fixed Monthly Service Charge Current Residential	Application #	Proposed	Customer Unit Cost per Month with PLCC Adjustment value
Kitchener- Wilmot Hydro (Proposed)	12.53		12.53	12.53
Cambridge and North Dumfries Hydro*	10.09	EB - 2009-0260	9.75	15.33
Guelph Hydro	14.10	EB - 2011-0123	16.53	21.62
London Hydro	13.12	EB - 2012-0146	12.72	11.81
Waterloo North Hydro	14.79	EB - 2010-0144	14.56	15.47

b) Please confirm that the fixed-variable splits used for the GS>50 and Large User classes were prior to adjusting variable revenues for the transformer ownership allowance. If yes, please re-calculate the fixed-variable split and the resulting monthly charge for each class after deducting this allowance.

Answer: **No, the splits are after the transformer allowance.**

End of Exhibit Eight Interrogatories

Board Staff Exhibit Nine Interrogatories

Exhibit 9 – Deferral and Variance Accounts

9-Staff-40 Ref: Exhibit 9/Tab 1/Schedule 1 – Differences from RRRs

On page 15 of this exhibit, KWHI states that the balances of Account 1588 – LRAMVA differs from the December RRR 2.1.7 Trial Balance as "[t]he transactions to this account were not recorded until after the trial balance for 2012 was submitted on April 30, 2012."

a) Please confirm the date that the 2012 trial balance was submitted to the Board under RRR 2.1.7.

Answer: **April 29, 2013.**

b) The final OPA report for 2011 CDM programs was issued to KWHI in 2012 Q3. Please explain why the Account 1568 entries were not recorded until after the 2012 trial balance was submitted.

Answer: **KWHI was unaware that the entries for 2011 OPA programs were to be recorded to account 1568 until after the financial audit was completed.**

9-Staff-41 Ref: Exhibit 9/Tab 1/Schedule 3 – Account 1508 sub-account IFRS Transition Costs

In this Exhibit, KWHI documents that it is applying for disposition of the IFRS Transition Costs sub-account balance, with a principal amount of $191,266 to December 31, 2012 plus carrying charges.

However, as KWHI has documented elsewhere in its Application, KWHI has not fully adopted IFRS for financial reporting purposes, and has not completed all changes necessary to adopt IFRS.

The Board's general policy and practice is not to dispose of the Account 1508 sub-account IFRS Transition Costs until the distributor has completed its adoption of IFRS for financial and regulatory purposes and so has a complete record of such costs to review.

Board staff notes that S.2.12.3 of the 2014 Filing Requirements refer to Accounting Procedures Handbook – FAQ #1 and FAQ #2, dated October 2009 and states the following with respect to the disposition of Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition:

> As per the October 2009 APH FAQ #1 and FAQ #2, an applicant must file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance, in its next cost of service rate application immediately after the IFRS transition period.

Given that KWHI's IFRS adoption will be on January 1, 2015 and given S.2.12.3 of the 2014 filing requirements, please explain why KWHI is seeking disposition of the $197,646 balance in this current rate application instead of requesting disposition in the next rate proceeding when the IFRS transition period is complete.

Answer: As stated in the application, KWHI will have ongoing costs related to the transition to IFRS; however, they are not expected to be overly material. KWHI began recording costs in 2009 for the IFRS transition and its next cost of service is not planned until 2018 (four year horizon). The deferred costs would remain on KWHI's balance sheet for up to nine years, which is quite a long time. KWHI therefore applied to clear what has been recorded up to now.

In addition, the Board issued a letter on July 17, 2012 which allowed distributors to maintain their accounting records using CGAAP methodologies but also required them to change their depreciation rates and the capitalization policies to be consistent with IFRS standards. The Board's letter would suggest most of the work to move to IFRS has been completed and the costs associated with this movement should be recoverable in this application.

9-Staff-42 Ref: Exhibit 9/Tab 1/Schedule 1/p. 11 and Accounting Procedures Handbook, Article 490, p. 9

The APH guidelines require the accrual of both revenues and expenses.

KWHI indicated that that it uses the accrual method of accounting for its expenses but did not indicate if KWHI uses accrual for DVA revenues.

a) What method of regulatory accounting, i.e. cash versus accrual, does KWHI use for its DVA revenues starting in 2012 and onwards?

Answer: KWHI uses the accrual method for both revenues and expenses.

b) If KWH does not use the accrual basis for its DVA revenues, please explain why not and please quantify the total accrued DVA revenues for 2012.

Answer: KWHI uses the accrual method for both revenues and expenses.

9-Staff-43 Ref: Exhibit 9/Tab 1/Schedule 1/p. 15, Exhibit 9/Tab 1/Schedule 2/Table 9-5 – Total Claim by Account Number, 2014 Filing Requirements for Transmission & Distribution Applications: Chapter 2 Appendices, Appendix 2-TB and DVA Work Form (WF) for 2013 Filers – Account 1592, PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits

Appendix 2-TB of the 2014 Filing Requirements requires that 100% of the balance in Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs) be recorded in this table in Appendix 2-TB.
KWHI is requesting disposition for the balance of $162,202, refund to customers for Account 1592, sub account HST/OVAT ITCs. KWHI indicates that the credit balance of $162,202 reported in the DVA WF in Account 1592 –PILS & Taxes Variance – Sub-account HST/OVAT is 50% of the balance reported in this sub-account as of December 31, 2013, as 50% of the savings flow back to customers (as per Board direction).
Board staff notes that KWHI did not provide the analysis required in the filing requirements.
Please complete and file Appendix 2-TB (an update issued on July 17, 2013 as part of the Filing Requirements for Transmission and Distribution Applications, replacing Appendix 2-T from the 2013 Filing Requirements) showing 100% of the balance in Account 1592, Sub-account HST/OVAT ITCs.

Answer: Included in Appendix A

9-Staff-44 Ref: Exhibit 2/Tab 3/Schedule 3, Appendix 2-B: Fixed Asset Continuity Schedules for 2011-13, Revenue Requirement Work Form/Cost of Capital Tab, Appendix 2-EB (as part of KWHI's August 9, 2013 update in response to the Board's Request for Information dated August 2-ED, Chapter 2 Filing Requirements for Electricity Distribution Rate Applications, S.2.12.5, p.53, dated July 17, 2013 - Account 1576, Accounting Changes Under CGAAP

In Appendix 2-ED, Board staff noted that there are differences between the individual balances listed under the PP&E Values under former CGAAP, the individual balances listed under the PP&E Values under the revised CGAAP and the balances in Appendix 2-B for 2012 and 2013. In addition, Board staff also noted that the Weighted Average Cost of Capital (WACC) rate used of 7.31% in Appendix 2-ED is different from the Revenue Requirement WACC of 5.99%.
Board policy and the 2014 filing requirements require the applicant to have a separate rate rider for disposition of the balance in Account 1576.

A separate volumetric rate rider for Account 1576 for the clearance of the Account balance over the proposed disposition period, including all calculations showing its derivation.

Board staff noted that, in the August 9, 2013 KWHI's letter responding to the Board's Request for Information, KWHI indicated that KWHI believes that the distribution revenue is the appropriate measure for this rate rider instead of KWHI's volumetric data as per the filing requirements.

a) Please reconcile all the figures under the former CGAAP and revised CGAAP in Appendix 2-ED to the applicable Appendices 2-B for the opening net PP&E, Net Additions, Net Depreciation, and Closing net PP&E for 2012 to 2013. Please file the necessary revised schedules if required.

Answer: **KWHI included WIP as per the Powerstream Decision (EB-2012-0161) in order to keep KWHI whole.**

	2012	WIP	As filed Appendix 2-ED	2013	WIP	As filed Appendix 2-ED
Opening Net PPE - Per Appendix 2-B	152,037,099	4,545,881	156,582,980	163,614,014	8,950,685	172,564,699
Net Additions	14,994,871	4,404,804	19,399,675	21,870,597	(4,212,885)	17,657,712
Net Depreciation	(3,417,956)		(3,417,956)	(7,305,052)		(7,305,052)
	163,614,014		172,564,699	178,179,559		182,917,359

b) Please update Appendix 2-ED to reflect the correct weighted average cost of capital and the 1576 rate rider calculation.

Answer: **Current filings requirements file have Appendix 2-ED as requested, without WIP, and reflect the correct weighted average cost of Capital.**

c) Please recalculate separate rate riders for Account 1576 using volumetric data.

Answer: **See table below:**

Rate Rider Calculation - Account 1576

Deferral and Variance Accounts	Balances at Dec. 31, 2013	ALLOCATOR	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor	Total
1576	$ (7,658,548)	kW hrs	$ (2,789,589)	$ (1,033,867)	$ (3,615,361)	$ (136,085)	$ (14,624)	$ (69,022)	$ -	$ (7,658,548)
Subtotal - Group 2	$ (7,658,548)		$ (2,789,589)	$ (1,033,867)	$ (3,615,361)	$ (136,085)	$ (14,624)	$ (69,022)	$ -	$ (7,658,548)
Balance to be collected or refunded, Variable	$ (7,658,548)		$ (2,789,589)	$ (1,033,867)	$ (3,615,361)	$ (136,085)	$ (14,624)	$ (69,022)	$ -	$ (7,658,548)
Number of years for Variable	4									
Balance to be collected or refunded per year, Variable	$ (1,914,637)		$ (697,397)	$ (258,467)	$ (903,840)	$ (34,021)	$ (3,656)	$ (17,256)	$ -	$ (1,914,637)

Class	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor
Deferral and Variance Account Rate Rider, Variable Billing Determinants	$ (0.0011) kWh	$ (0.0011) kWh	$ (0.4188) kW	$ (0.5400) kW	$ (0.0011) kWh	$ (0.3822) kW	$ - kW

9-Staff-45 Ref: Exhibit 9/Tab 1/Schedule 1/p. 16 & Table 9-4 "Interest Calculation to December 31, 2013 on Deferral and Variance Account Balances" and Exhibit 9/Tab 1/Schedule 2/Table 9-5 and Table 9-10 "Rate Rider Calculation (Net of Global Adjustment)"

At the first reference, on page 16, there is an amount of $37,405 shown under the column "Total" for the "Renewable Connection –OM&A - Account 1532".

The Report of the Board referenced in 2-Staff-2, requires that any distributor who incurred eligible capital and OM&A costs necessary for the purpose of "enabling the connection of qualifying generation facility" (see page 3 at Section 1.1 Regulation 330/09, & first bullet) to calculate the "direct benefits" to customers of the distributor (KWHI in this case) per Section 3.2.2.3 of that same Report of the Board.

a) Please re-file an amended Table 9-4 of the first reference after removing the $37,405 amount for Renewable Connection – OM&A , Account No.1532

Answer: Amended Table 9-4 below. Account 1532 has been moved down the table as to be excluded from any calculations.

Table 9-4
Interest Calculation to December 31, 2013 on Deferral and Variance Account Balances

Account Description	Account Number	Principal Amounts as of Dec-31 2012	Interest to Dec 31-12	Interest Jan-1 to Dec31-13	Total
RSVA - Wholesale Market Service Charge	1580	$ (6,598,717)	$ (111,640)	$ (97,001)	$ (6,807,358)
RSVA - Retail Transmission Network Charge	1584	$ 3,985,418	$ 111,633	$ 58,586	$ 4,155,637
RSVA - Retail Transmission Connection Charge	1586	$ 279,221	$ 11,929	$ 4,105	$ 295,255
RSVA - Power	1588	$ 1,457,199	$ (19,827)	$ 21,421	$ 1,458,793
RSVA - Global Adjustment	1589	$ 2,847,113	$ 59,450	$ 41,853	$ 2,948,416
Recovery of Regulatory Asset Balances (2010)	1595	$ 572,229	$ (209,270)	$ 8,412	$ 371,371
Recovery of Regulatory Asset Balances (2011)	1595	$ 525,256	$ (12,569)	$ 7,721	$ 520,408
Recovery of Regulatory Asset Balances (2012)	1595	$ (315,091)	$ 161,151	$ (4,632)	$ (158,573)
Sub-Totals		$ 2,752,627	$ (9,142)	$ 40,464	$ 2,783,949
Other Regulatory Assets - Sub-Account - IFRS Transition Costs	1508	$ 191,266	$ 3,569	$ 2,812	$ 197,646
Retail Cost Variance Account - Retail	1518	$ (67,075)	$ (3,346)	$ (986)	$ (71,407)
Retail Cost Variance Account - STR	1548	$ 38,149	$ 1,342	$ 561	$ 40,052
LRAM Variance Account	1568	$ 405,585	$ 3,867	$ 4,898	$ 414,350
PILS & Taxes Variance - 2006 & Subsequent Years	1592	$ (219,331)	$ (22,224)	$ (3,224)	$ (244,779)
PILS & Taxes Variance - Sub-Account HST/OVAT	1592	$ (142,429)	$ (17,680)	$ (2,094)	$ (162,202)
Sub-Totals		$ 206,165	$ (34,472)	$ 1,967	$ 173,660
Totals per column		**$ 2,958,792**	**$ (43,614)**	**$ 42,430**	**$ 2,957,608**
Accounts Excluded from Disposition					
Smart Grid OM&A	1535	$ 20,000	$ 234	$ -	$ 20,234
Smart Meter OM&A	1556	$ (89,498)	$ -	$ -	$ (89,498)
PILS Contra	1563	$ 390,134	$ 22,224	$ 5,735	$ 418,093
PILS & Taxes Variance - Sub-Account HST/OVAT	1592	$ 142,429	$ 17,680	$ 5,318	$ 165,426
Sub-Totals		$ 463,064	$ 40,137	$ 11,053	$ 514,255
Accounts Excluded due to Other Treatments					
Renewable Connection - Capital	1531	$ 114,473	$ 1,830	$ 1,683	$ 117,986
Renewable Connection - OM&A	1532	$ 36,410	$ 460	$ 535	$ 37,405
Smart Meter Capital - Sub-Account Stranded Meters	1555	$ 3,185,102	$ -	$ -	$ 3,185,102
Accounting Changes Under CGAAP	1576	$ (2,265,213)	$ -	$ -	$ (2,265,213)
Sub-Totals		$ 1,070,772	$ 2,290	$ 2,218	$ 1,075,280
Totals per column		**$ 4,492,629**	**$ (1,187)**	**$ 55,701**	**$ 4,547,143**
Annual interest rate:		1.47%			

b) Please re-file an amended Table 9-5 in the second reference, to remove the $37,405 amount for Renewable Connection – OM&A , Account No.1532

Answer: Amended Table 9-5 below.

Table 9-5 - Total Claim by Account Number

Account Description		Account Number		Principal Amounts as of Dec-31 2012		Interest to Dec31-12		Interest Jan-1 to Dec 31-13		Total Claim
RSVA - Wholesale Market Service Charge		1580	$	(6,598,717)	$	(111,640)	$	(97,001)	$	(6,807,358)
RSVA - Retail Transmission Network Charge		1584	$	3,985,418	$	111,633	$	58,586	$	4,155,637
RSVA - Retail Transmission Connection Charge		1586	$	279,221	$	11,929	$	4,105	$	295,255
RSVA - Power		1588	$	1,457,199	$	(19,827)	$	21,421	$	1,458,793
Recovery of Regulatory Asset Balances (2012)		1595	$	572,229	$	(209,270)	$	8,412	$	371,371
Sub-Group 1 excluding Global Adjustment			$	(304,650)	$	(217,174)	$	(4,478)	$	(526,302)
RSVA - Global Adjustment		1589	$	2,847,113	$	59,450	$	41,853	$	2,948,416
Sub-Group 1 including Global Adjustment			$	2,542,463	$	(157,724)	$	37,374	$	2,422,113
Other Regulatory Assets - Sub-Account - IFRS Transition Costs		1508	$	191,266	$	3,569	$	2,812	$	197,646
Retail Cost Variance Account - Retail		1518	$	(67,075)	$	(3,346)	$	(986)	$	(71,407)
Retail Cost Variance Account - STR		1548	$	38,149	$	1,342	$	561	$	40,052
LRAM Variance Account		1568	$	405,585	$	3,867	$	4,898	$	414,350
PILS & Taxes Variance - 2006 & Subsequent Years		1592	$	(219,331)	$	(22,224)	$	(3,224)	$	(244,779)
PILS & Taxes Variance - Sub-Account HST/OVAT	(1)	1592	$	(142,429)	$	(17,680)	$	(2,094)	$	(162,202)
Sub-Group 2			$	206,165	$	(34,472)	$	1,967	$	173,660
Totals per column			$	2,748,628	$	(192,196)	$	39,341	$	2,595,773
Annual interest rate:				1.47%						

(1) December 31, 2012 balance @ 50%

c) Please file a an amended Table 9-10 in the second reference to include in the rate rider calculation the direct benefit portion of the $307, 405 for r the deferral account 1532 per the following approach:

- First, calculate the "direct benefit" calculation, as prescribed in the second reference, on the $37,405 since the noted OM&A amount is an eligible amount according to the Report of the Board; and

Answer: Included in Appendix A.

- Calculate a rate rider to dispose of and recover the portion designated as direct benefit, from the calculation in the bullet above.

Answer: See the table below:

Rate Rider Calculation (Net of Global Adjustment) - 1532 and 1568 Adjusted

Deferral and Variance Accounts	Balances at Dec. 31, 2013	ALLOCATOR	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor	Total
RSVA - Wholesale Market Service Charge	$ (6,807,358)	kWh - No Embedded Distributor	$ (2,479,547)	$ (918,961)	$ (3,213,540)	$ (120,960)	$ (12,999)	$ (61,351)	$ -	$ (6,807,358)
RSVA - Retail Transmission Network Charge	$ 4,155,637	kWh - Embedded Distributor	$ 1,496,669	$ 554,690	$ 1,939,712	$ 73,012	$ 7,846	$ 37,032	$ 46,676	$ 4,155,637
RSVA - Retail Transmission Connection Charge	$ 295,255	kWh - Embedded Distributor	$ 106,337	$ 39,410	$ 137,815	$ 5,187	$ 557	$ 2,631	$ 3,316	$ 295,255
RSVA - Power	$ 1,458,793	kWh - No Embedded Distributor	$ 531,358	$ 196,930	$ 688,651	$ 25,921	$ 2,786	$ 13,147	$ -	$ 1,458,793
RSVA - Global Adjustment	$ -	kWh for non-RPP customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances (2010)	$ 371,371	Recovery Share	$ 146,298	$ 59,668	$ 157,034	$ 4,327	$ -	$ 4,044	$ -	$ 371,371
Subtotal - Group 1	**$ (526,302)**		**$ (198,885)**	**$ (68,262)**	**$ (290,329)**	**$ (12,512)**	**$ (1,810)**	**$ (4,497)**	**$ 49,992**	**$ (526,302)**
Other Regulatory Assets-Sub-Account - IFRS Transition Costs	$ 197,646	Distribution Revenue	$ 103,503	$ 27,938	$ 60,059	$ 2,737	$ 760	$ 2,360	$ 289	$ 197,646
Retail Cost Variance Account - Retail	$ (71,407)	# of Customers	$ (62,839)	$ (5,958)	$ (719)	$ (1)	$ (677)	$ (1,211)	$ (1)	$ (71,407)
Renewable Connection - OM&A	$ 3,209	Distribution Revenue	$ 1,680	$ 454	$ 975	$ 44	$ 12	$ 38	$ 5	$ 3,209
Retail Cost Variance Account - STR	$ 40,052	# of Customers	$ 35,246	$ 3,342	$ 403	$ 0	$ 380	$ 680	$ 0	$ 40,052
LRAM Variance Account	$ 392,254	CDM Savings	$ 110,977	$ 112,929	$ 168,348	$ -	$ -	$ -	$ -	$ 392,254
PILS & Taxes Variance - 2006 & Subsequent Years	$ (244,779)	Distribution Revenue	$ (128,186)	$ (34,601)	$ (74,381)	$ (3,390)	$ (942)	$ (2,923)	$ (357)	$ (244,779)
PILS & Taxes Variance - Sub-Account HST/OVAT	$ (162,202)	Distribution Revenue	$ (84,942)	$ (22,928)	$ (49,288)	$ (2,246)	$ (624)	$ (1,937)	$ (237)	$ (162,202)
Subtotal - Group 2	**$ 154,772**		**$ (24,559)**	**$ 81,175**	**$ 105,396**	**$ (2,855)**	**$ (1,090)**	**$ (2,993)**	**$ (301)**	**$ 154,772**
Total to be Recovered	**$ (371,530)**		**$ (223,444)**	**$ 12,913**	**$ (184,933)**	**$ (15,367)**	**$ (2,900)**	**$ (7,490)**	**$ 49,691**	**$ (371,530)**
Balance to be collected or refunded, Variable	$ (371,530)		$ (223,444)	$ 12,913	$ (184,933)	$ (15,367)	$ (2,900)	$ (7,490)	$ 49,691	$ (371,530)
Number of years for Variable	1									
Balance to be collected or refunded per year, Variable	$ (371,530)		$ (223,444)	$ 12,913	$ (184,933)	$ (15,367)	$ (2,900)	$ (7,490)	$ 49,691	$ (371,530)

Class	Residential	GS < 50 KW	GS > 50 Non TOU	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor
Deferral and Variance Account Rate Rider, Variable	$ (0.0003)	$ 0.0001	$ (0.0857)	$ (0.2439)	$ (0.0008)	$ (0.1659)	$ 1.1123
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

LRAMVA

9-Staff-46 Ref: Exhibit 9/Tab 1/Schedule 1, Exhibit 9/Tab 1/Schedule 2, Exhibit 9/Tab 1/Schedule 8 and Exhibit 9/Tab 1/Schedule 11/Attachment 2 of 13 – Appendix B – Account 1568 – LRAMVA

KWHI states that it is applying for disposition of the Account 1568 balance of $414,350, pertaining to the lost revenues from the impact of 2011 CDM programs, including 2010 CDM programs completed in 2011, in 2011 and the persistence in 2012 and 2013 (i.e. up to December 31, 2013).

KWHI is requesting approval of 2011 persisting lost revenues into 2012 and 2013. The persisting 2011 lost revenues in 2012 are $133,215 and in 2013 is $134,156. 2011 lost revenues in 2011 equals $138,214.

a) What balances of Account 1568 have been audited?

Answer: As stated in the application, the balance of account 1568 has not been audited; however, the balances are based on the third-party OPA CDM report and verified by Burman Energy.

b) In other applications, the Board has generally approved the disposition of DVA balances corresponding to the last Audited Financial Statements. In this Application, KWHI's latest Audited Financial Statements are as of December 31, 2012, and KWHI has requested disposition of other Group 1 and Group 2 DVA balances to December 31, 2012 plus carrying charges to December 31, 2013.

i. Please provide KWHI's views on amending the LRAMVA request to dispose of the balance as of December 31, 2012 plus carrying charges to December 31, 2013.

Answer: KWHI has updated its LRAMVA request. It has consulted with Burman Energy on the LRAMVA. Burman Energy clarified with Board staff that KWHI is eligible for recoveries relating to 2011 & 2012 program results plus 2011 program results persisting into 2012. It was noted that KWHI should update its application to recover the 2012 program results since they were not available at the time that KWHI filed its application.

The updated results were submitted to Burman Energy so that new 1568 LRAMVA balances could be calculated. KWHI has recalculated the LRAMVA based on this updated information. The detail used to calculate the LRAMVA claim is attached as Appendix F. The revised LRAM claim is $381,936 as shown below:

Total LRAM Claim - balance as of December 31, 2012	**381,936**
Carrying Charges to December 31, 2012	**4,703**
Carrying Charges to December 31, 2013	**5,614**
Total LRAM Claim with carrying charges to December 31, 2013	**392,254**

The revised rate riders are shown below:

Rate Rider Calculation (Net of Global Adjustment) - 1531, 1532 Added and 1568 Adjusted

Deferral and Variance Accounts	Balances at Dec. 31, 2013	ALLOCATOR	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor	Total
RSVA - Wholesale Market Service Charge	$ (6,807,358)	kWh - No Embedded Distributor	$ (2,479,547)	$ (918,961)	$ (3,213,540)	$ (120,960)	$ (12,999)	$ (61,351)	$ -	$ (6,807,358)
RSVA - Retail Transmission Network Charge	$ 4,155,637	kWh - Embedded Distributor	$ 1,496,669	$ 554,690	$ 1,939,712	$ 73,012	$ 7,846	$ 37,032	$ 46,676	$ 4,155,637
RSVA - Retail Transmission Connection Charge	$ 295,255	kWh - Embedded Distributor	$ 106,337	$ 39,410	$ 137,815	$ 5,187	$ 557	$ 2,631	$ 3,316	$ 295,255
RSVA - Power	$ 1,458,793	kWh - No Embedded Distributor	$ 531,358	$ 196,930	$ 688,651	$ 25,921	$ 2,786	$ 13,147	$ -	$ 1,458,793
RSVA - Global Adjustment	$ -	kWh for non-RPP customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances (2010)	$ 371,371	Recovery Share	$ 146,298	$ 59,668	$ 157,034	$ 4,327	$ -	$ 4,044	$ -	$ 371,371
Subtotal - Group 1	**$ (526,302)**		**$ (198,885)**	**$ (68,262)**	**$ (290,329)**	**$ (12,512)**	**$ (1,810)**	**$ (4,497)**	**$ 49,992**	**$ (526,302)**
Other Regulatory Assets-Sub-Account - IFRS Transition Costs	$ 197,646	Distribution Revenue	$ 103,503	$ 27,938	$ 60,059	$ 2,737	$ 760	$ 2,360	$ 289	$ 197,646
Retail Cost Variance Account - Retail	$ (71,407)	# of Customers	$ (62,839)	$ (5,958)	$ (719)	$ (1)	$ (677)	$ (1,211)	$ (1)	$ (71,407)
Renewable Connection - Capital	$ 7,079	Distribution Revenue	$ 3,707	$ 1,001	$ 2,151	$ 98	$ 27	$ 85	$ 10	$ 7,079
Renewable Connection - OM&A	$ 3,209	Distribution Revenue	$ 1,680	$ 454	$ 975	$ 44	$ 12	$ 38	$ 5	$ 3,209
Retail Cost Variance Account - STR	$ 40,052	# of Customers	$ 35,246	$ 3,342	$ 403	$ 0	$ 380	$ 680	$ 0	$ 40,052
LRAM Variance Account	$ 392,254	CDM Savings	$ 110,977	$ 112,929	$ 168,348	$ -	$ -	$ -	$ -	$ 392,254
PILS & Taxes Variance - 2006 & Subsequent Years	$ (244,779)	Distribution Revenue	$ (128,186)	$ (34,601)	$ (74,381)	$ (3,390)	$ (942)	$ (2,923)	$ (357)	$ (244,779)
PILS & Taxes Variance - Sub-Account HST/OVAT	$ (162,202)	Distribution Revenue	$ (84,942)	$ (22,928)	$ (49,288)	$ (2,246)	$ (624)	$ (1,937)	$ (237)	$ (162,202)
Subtotal - Group 2	**$ 161,851**		**$ (20,852)**	**$ 82,176**	**$ 107,547**	**$ (2,757)**	**$ (1,063)**	**$ (2,909)**	**$ (291)**	**$ 161,851**
Total to be Recovered	**$ (364,451)**		**$ (219,737)**	**$ 13,913**	**$ (182,782)**	**$ (15,269)**	**$ (2,873)**	**$ (7,405)**	**$ 49,701**	**$ (364,451)**
Balance to be collected or refunded, Variable	$ (364,451)		$ (219,737)	$ 13,913	$ (182,782)	$ (15,269)	$ (2,873)	$ (7,405)	$ 49,701	$ (364,451)
Number of years for Variable	**1**									
Balance to be collected or refunded per year, Variable	$ (364,451)		$ (219,737)	$ 13,913	$ (182,782)	$ (15,269)	$ (2,873)	$ (7,405)	$ 49,701	$ (364,451)

Class	**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**Large User**	**Unmetered Scattered Load**	**Street Lighting**	**Embedded Distributor**
Deferral and Variance Account Rate Rider, Variable	$ (0.0003)	$ 0.0001	$ (0.0847)	$ (0.2424)	$ (0.0008)	$ (0.1640)	$ 1.1125
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

ii. Please provide the calculations showing what would be the Account 1568 principal balance to December 31, 2012 plus carrying charges to December 31, 2013.

Answer: See answer above. KWHI has updated its LRAMVA amounts based on the new information. The calculations for carrying charges in total and by class are attached as Appendix F.

c) In Table 9-5, KWHI shows the Principal Balance for Account 1568 as of December 31, 2012 being $405,585, and carrying charges calculated for January 1 to December 31, 2013 based on that principal balance. In Table 9-21, KWHI shows the 2011 CDM program impacts and persistence by year and customer class, showing that the cumulative impact to December 31, 2012 is $271,429 and the cumulative impact to December 31, 2013 is $405,585. Please reconcile Tables 9-5 and 9-21 as to what is the balance at the end of each year and the calculation of the carrying charges based on applying the prescribed interest rate to the opening principal balance in each month.

Answer: The differences consisted of the persistence into 2013 which has been removed now that the LRAMVA claim has been updated.

d) Please discuss why the 2011 persisting LRAMVA amounts are lower in 2012 than they are in 2013.

Answer: The actual kW and kWh are higher in 2012 than in 2013. However, the dollar amount for 2013 is higher because the rates for 2013 increased from 2012 to 2013.

e) Please discuss the methodology that was followed in calculating KWHI's 2011 persisting CDM savings in 2012 and 2013.

Answer: The persisting CDM savings were provided by Jodi Amy at the OPA. See below:

All savings are at the end-user level

Net Annual Peak Demand Savings (MW)

Program	Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Consumer	Appliance Exchange	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consumer	Appliance Retirement	0.04	0.04	0.04	0.03	0.02	0.00	0.00	0.00	0.00	0.00
Consumer	Bi-Annual Retailer Event	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.01
Consumer	Conservation Instant Coupon Booklet	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.01
Consumer	HVAC Incentives	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
Consumer	Residential Demand Response	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consumer	Retailer Co-op	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		0.88	**0.73**	**0.73**	**0.73**	**0.71**	**0.68**	**0.67**	**0.67**	**0.68**	**0.66**
C&I	Commercial Demand Response (part of the Residential program schedule)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C&I	Demand Response 3 (part of the Industrial program schedule)	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C&I	Direct Install Lighting	0.26	0.26	0.26	0.21	0.21	0.21	0.08	0.07	0.07	0.07
C&I	Efficiency: Equipment Replacement	0.56	0.56	0.56	0.55	0.46	0.42	0.39	0.39	0.33	0.33
		1.29	**0.82**	**0.82**	**0.76**	**0.67**	**0.64**	**0.47**	**0.46**	**0.40**	**0.40**
Industrial	Demand Response 3	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03
		1.49	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.03**	**0.03**
Pre-2011 Programs Completed in 2011	Electricity Retrofit Incentive Program	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Pre-2011 Programs Completed in 2011	High Performance New Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grand Total		**4.63**	**2.56**	**2.56**	**2.49**	**2.38**	**2.32**	**2.14**	**2.14**	**2.08**	**2.06**

Net Annual Energy Savings (MWh)

Program	Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Consumer	Appliance Exchange	9	9	9	5	0	0	0	0	0	0
Consumer	Appliance Retirement	263	263	263	262	187	0	0	0	0	0
Consumer	Bi-Annual Retailer Event	479	479	479	479	438	393	296	295	382	122
Consumer	Conservation Instant Coupon Booklet	306	306	306	306	281	254	199	198	249	95
Consumer	HVAC Incentives	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Consumer	Residential Demand Response	0	0	0	0	0	0	0	0	0	0
Consumer	Retailer Co-op	0	0	0	0	0	0	0	0	0	0
		2,234	**2,234**	**2,234**	**2,230**	**2,084**	**1,826**	**1,673**	**1,671**	**1,809**	**1,396**
C&I	Commercial Demand Response (part of the Residential program schedule)	0	0	0	0	0	0	0	0	0	0
C&I	Demand Response 3 (part of the Industrial program schedule)	18	0	0	0	0	0	0	0	0	0
C&I	Direct Install Lighting	631	629	618	495	495	495	177	172	172	172
C&I	Efficiency: Equipment Replacement	3,057	3,057	3,057	3,007	2,537	2,404	2,267	2,267	2,049	2,049
		3,706	**3,686**	**3,676**	**3,502**	**3,032**	**2,899**	**2,443**	**2,439**	**2,221**	**2,221**
Industrial	Demand Response 3	85	0	0	0	0	0	0	0	0	0
Industrial	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	271	271	271	271	271	271	260	260	247	247
		356	**271**	**271**	**271**	**271**	**271**	**260**	**260**	**247**	**247**
Pre-2011 Programs Completed in 2011	Electricity Retrofit Incentive Program	6,580	6,580	6,580	6,580	6,580	6,580	6,580	6,580	6,580	6,580
Pre-2011 Programs Completed in 2011	High Performance New Construction	5	5	5	5	5	5	5	5	5	5
Grand Total		**12,883**	**12,777**	**12,767**	**12,588**	**11,973**	**11,581**	**10,962**	**10,955**	**10,862**	**10,449**

9-Staff-47 Ref: Exhibit 9/Tab 1/Schedule 1/page 9 and Exhibit 9/Tab 1/ Schedule 8/Table 9-1

KWHI has requested approval for clearance of its LRAMVA – Account 1568 in the amount of $414,350, which includes $8,765 in carrying charges. KWHI's LRAMVA amount includes lost revenues from 2011 OPA Province-Wide CDM Programs in 2011 and persisting in 2012 and 2013.

Please reconcile the LRAMVA amount of $414,350 found at Exhibit 9/Tab 1/Schedule 8/pg. 9 with the LRAMVA amount of $409,452 in the Table 9-1 at Exhibit 9/Tab 1/Schedule 8. Please discuss why there is a difference.

Answer: The amounts have now been adjusted – see 9-Staff 46. In the case of the earlier submission, the differences were interest of $4,898 calculated on the monthly opening balance for January through December. The balances for each month were been adjusted for the 2013 persistence of $134,155 earned evenly throughout the year; thus the interest had not been calculated on the closing December 31, 2012 closing balance. Rather the interest had been calculated on the December 31, 2012 closing balance plus increases monthly for the $134,155 earned monthly throughout 2013.

Stranded Meters

9-Staff-48 Ref: Exhibit 9/Tab 1/Schedule 7 – Stranded Meters

On page 3 of this exhibit, KWHI states:

> KWHI has split the costs of the stranded conventional meters by using the split calculated in its 2007 Cost Allocation Informational Filing, Sheet 17.1 Meter Capital (attached as Appendix C). Table 9-20 below shows the breakdown of stranded meter costs by rate class. Note the total Stranded Meters by Class (C) is the net book value as of December 31, 2013.

Please confirm that the reference should be to Exhibit 9/Tab 1/Schedule 11/Appendix I.

Answer: Confirmed.

End of Board Staff Exhibit Nine Interrogatories

Energy Probe Exhibit Nine Interrogatories

9-Energy Probe-59

Ref: Exhibit 9, Tab 1, Schedule 9 &
August 9 Update

a) Please explain the different net additions and net depreciation amounts shown for 2013 in the August 9 Update (Appendix 2-ED) relative to that shown in Table 9-28 in the original evidence.

Answer: Table 9-28 as originally filed balances to KWHI external financial statements. Appendix 2-ED as filed in the August 9th balances to the Appendix 2-b, with the exception that Appendix 2-b does not includes WIP and Appendix 2-ED as filed August 9th does. Appendix 2-ED has been re-submitted (see 9-STAFF – 44) without the WIP.

b) Please explain how KWHI earned the "excess" return on the account balance as noted on the first page under Board Information Request #3.

Answer: During the period 2010-2014, KWHI earned a return of 7.31% on its assets. During the period 2014-2018 KWHI will earn a return of 5.99%. The assets that have been revalued are assets that were in use during the period 2010-2014. Therefore, the return that was earned on them was the 7.31%. After the Cost of Service, the assets will return 5.99% and this return is reflected in the rates being applied for. Therefore, only the return that was earned on the assets during the prior rebasing period (2010-2014) should be returned to shareholders and the ratepayers.

c) Please provide a version of Appendix 2-ED that reflects the WACC applied for in 2014 and follows the calculation shown in Note 2.

Answer: See 9-STAFF-44 – updated Appendix 2-ED.

d) Please show where the Distribution Revenue allocator is calculated that is proposed to be used as the allocator for Account 1576.

Answer: KWHI inadvertently used an incorrect allocator (see 9-STAFF- 44) and is not as per the OEB letter dated June 25, 2013. See 9-STAFF-44 where this has been corrected.

The allocators, as originally filed, are shown in the tables below:

Table 6

2014 Allocates by Class

2010 Data By Class	kW	kWhs	Cust. Num.'s	# of Metered Customers	kWh for non-RPP customers (2012)	Distribution Revenue (2012)	% of CDM Expenditures
RESIDENTIAL		651,842,779	82,577	82,577	40,365,728	20,199,551	28.29%
GENERAL SERVICE <50 KW		241,583,580	7,830	7,830	34,597,542	5,452,442	28.79%
GENERAL SERVICE >50 KW	2,158,320	844,800,841	945	945	756,939,530	11,720,999	42.92%
LARGE USER	63,002	31,798,990	1	1	69,911,509	534,133	0.00%
UNMETERED SCATTERED LOADS	0	3,417,188	890	21	0	148,389	0.00%
STREET LIGHTING	45,145	16,128,465	1,592	6	16,350,066	460,546	0.00%
Totals	2,266,467	1,789,571,844	93,835	91,380	918,164,375	38,516,059	100.00%
EMBEDDED DISTRIBUTOR	44,674	20,328,822	1	1	0	56,329	0.00%
Totals	2,311,141	1,809,900,666	93,836	91,381	918,164,375	38,572,388	100.00%

Table 8

2014 Allocates by Class on % Basis - Embedded Distributor Included

Allocators	kW	kWhs	Cust. Num.'s	# of Metered Customers	kWh for non-RPP Customers (2012)	Distribution Revenue (2012)	Recovery Share
RESIDENTIAL		36.02%	88.00%	90.37%	4.40%	52.37%	39.39%
GENERAL SERVICE <50 KW		13.35%	8.34%	8.57%	3.77%	14.14%	16.07%
GENERAL SERVICE >50 KW	93.39%	46.68%	1.01%	1.03%	82.44%	30.39%	42.29%
LARGE USER	2.73%	1.76%	0.00%	0.00%	7.61%	1.38%	1.17%
UNMETERED & SCATTERED LOADS		0.19%	0.95%	0.02%	0.00%	0.38%	0.00%
STREET LIGHTING	1.95%	0.89%	1.70%	0.01%	1.78%	1.19%	1.09%
EMBEDDED DISTRIBUTOR	1.93%	1.12%	0.00%	0.00%	0.00%	0.15%	0.00%
Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

e) Please provide the allocation by rate class if Total Net Plant plus Directly Allocated Net Fixed Assets (from sheet O1 of the cost allocation model) were used as the allocator for Account 1576, in the same format as that shown in the August 9 material.

Answer: Using the balance of 1576 as calculated above, and using the Cost allocation model as filed on August 9th, the following rate riders would be calculated:

Rate Rider Calculation - Account 1576

Deferral and Variance Accounts	Balances at Dec. 31, 2013	ALLOCATOR	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor
1576	$ (7,658,548)	As per Energy Probe	$ (4,106,654)	$ (1,046,128)	$ (2,321,911)	$ (60,333)	$ (80,518)	$ (20,408)	$ (22,596)
Subtotal - Group 2	**$ (7,658,548)**		**$ (4,106,654)**	**$ (1,046,128)**	**$ (2,321,911)**	**$ (60,333)**	**$ (80,518)**	**$ (20,408)**	**$ (22,596)**
Balance to be collected or refunded, Variable	$ (7,658,548)		$ (4,106,654)	$ (1,046,128)	$ (2,321,911)	$ (60,333)	$ (80,518)	$ (20,408)	$ (22,596)
Number of years for Variable	4								
Balance to be collected or refunded per year, Variable	$ (1,914,637)		$ (1,026,663)	$ (261,532)	$ (580,478)	$ (15,083)	$ (20,130)	$ (5,102)	$ (5,649)

Class	Residential	GS < 50	GS > 50	Large User	Unmetered Scattered Load	Street Lighting	Embedded Distributor
Deferral and Variance Account Rate Rider, Variable	$ (0.0016)	$ (0.0011)	$ (0.2689)	$ (0.2394)	$ (0.0059)	$ (0.1130)	$ (0.1265)
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

End of Energy Probe Exhibit Nine Interrogatories

No School Energy Coalition Exhibit Nine Interrogatories

VECC Exhibit Nine Interrogatories

9.0-VECC – 37 *(Re-numbered – originally 8.0-VECC-37)*

Reference: Exhibit 9, Tab 1, Schedule 9

a) In respect to Account 1576, KWHI notes that the calculation is in conformance with the Board's FAQ of July 2012. Is the balance in conformance with the Board's further direction of June 25, 2013 and specifically the inclusion of return component?

Answer: In the updated materials filed August 9th and 13th, KWHI complied with the updated direction of June 25th, 2013. See Staff inquiry 9-STAFF-44 for further information

9.0-VECC – 38 *(Re-numbered – originally 8.0-VECC-37)*

Reference: Exhibit 9, Tab 1, Schedule 6, pg. 68

b) KWHI is applying for LRAMVA program persistence for 2013. However, OPA results for 2013 are still outstanding. Please confirm that KWHI believes this request is in accordance with 2012 Guidelines for Conservation and Demand Management EB-2012-

0003, Appendix A, page 1 which appears to show that LDCs who rebase in 2013 on a future test year are only eligible for 2013 programs and 2012 and 2011 persistence amounts.

Answer: **KWHI has consulted with Burman Energy on the LRAMVA. Burman Energy clarified with Board staff that KWHI is eligible for recoveries relating to 2011 & 2012 program results plus 2011 program results persisting into 2012. It was noted that KWHI should update its application to recover the 2012 program results since they were not available at the time that KWHI filed its application.**

See 9-Staff-46 for updated information on the LRAM claim.

End of Interrogatories

Appendix 2-CN
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

Year 2012 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 3,266,775	$ 1,980,703	$ 1,286,072	$ 326,748	$ 1,449,446	5.00	20.00%	$ 289,889	$ 322,564	-$ 32,675
1611	Computer Software (Formally known as Account 1925) - Smart Meters	$ -		$ -	$ 518,017	$ 259,009	3.00	33.33%	$ 420,712	$ 420,712	$ -
1612	Land Rights (Formally known as Account 1906)	$ 265,447	$ 199,131	$ 66,316		$ 66,316	25.00	4.00%	$ 2,653	$ 2,653	-$ 0
1805	Land	$ 2,339,959		$ 2,339,959		$ 2,339,959	-	0.00%	$ -		$ -
1808	Buildings	$ 7,461,079		$ 7,461,079	-$ 20,178	$ 7,450,990	50.00	2.00%	$ 149,020	$ 149,020	-$ 0
1808	Buildings	$ 1,807,586		$ 1,807,586		$ 1,807,586	60.00	1.67%	$ 30,126	$ 30,200	-$ 74
1810	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 59,878,131	$ 1,369,865	$ 58,508,266	$ 93,639	$ 58,555,086	40.00	2.50%	$ 1,463,877	$ 1,464,704	-$ 827
1820	Distribution Station Equipment <50 kV	$ 2,853,105	$ 527,835	$ 2,325,270		$ 2,325,270	30.00	3.33%	$ 77,509	$ 77,457	$ 52
1825	Storage Battery Equipment			$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 29,644,770		$ 29,644,770	$ 2,894,738	$ 31,092,139	25.00	4.00%	$ 1,243,686	$ 1,301,580	-$ 57,894
1835	Overhead Conductors & Devices	$ 32,204,259		$ 32,204,259	$ 2,259,990	$ 33,334,254	25.00	4.00%	$ 1,333,370	$ 1,378,570	-$ 45,200
1840	Underground Conduit	$ 20,808,671		$ 20,808,671	$ 1,910,830	$ 21,764,086	25.00	4.00%	$ 870,563	$ 908,716	-$ 38,153
1840	Underground Conduit	$ 1,232,070		$ 1,232,070		$ 1,232,070	35.00	2.86%	$ 35,202	$ 35,202	-$ -
1845	Underground Conductors & Devices	$ 34,266,706		$ 34,266,706	$ 2,430,148	$ 35,481,780	25.00	4.00%	$ 1,419,271	$ 1,467,714	-$ 48,443
1845	Underground Conductors & Devices	$ 3,058,251		$ 3,058,251		$ 3,058,251	35.00	2.86%	$ 87,379	$ 87,379	-$ 0
1850	Line Transformers	$ 47,742,316		$ 47,742,316	$ 3,398,190	$ 49,441,411	25.00	4.00%	$ 1,977,656	$ 2,045,619	-$ 67,963
1850	Line Transformers	$ 2,180,161		$ 2,180,161		$ 2,180,161	30.00	3.33%	$ 72,672	$ 72,672	$ 0
1855	Services (Overhead & Underground)	$ 39,590,233		$ 39,590,233	$ 2,762,234	$ 40,971,350	25.00	4.00%	$ 1,638,854	$ 1,694,413	-$ 55,559
1855	Services (Overhead & Underground)	$ 1,885,469		$ 1,885,469		$ 1,885,469	35.00	2.86%	$ 53,871	$ 53,871	-$ 0
1860	Meters	$ 11,503,383	$ 9,578,658	$ 1,924,725	$ 367,352	$ 2,108,401	25.00	4.00%	$ 84,336	$ 598,483	-$ 514,147
1860	Meters			$ -	$ 101,351	$ 50,676	15.00	6.67%	$ 3,378	$ 6,495	-$ 3,117
1860	Meters (Smart Meters)			$ -	$ 11,943,758	$ 5,971,879	15.00	6.67%	$ 2,381,184	$ 2,381,184	$ -
1905	Land	$ 1,395,300		$ 1,395,300		$ 1,395,300	-	0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 3,877,327		$ 3,877,327	$ 31,703	$ 3,893,179	50.00	2.00%	$ 77,864	$ 78,181	-$ 317
1908	Buildings & Fixtures	$ 6,367,626		$ 6,367,626		$ 6,367,626	60.00	1.67%	$ 106,127	$ 106,127	$ 0
1910	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 1,112,311	$ 493,072	$ 619,239	$ 34,301	$ 636,390	10.00	10.00%	$ 63,639	$ 65,354	-$ 1,715
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware	$ 2,420,463	$ 1,891,874	$ 528,589	$ 227,721	$ 642,450	5.00	20.00%	$ 128,490	$ 151,267	-$ 22,777
1920	Computer Equip.-Hardware Smart Meters			$ -	$ 221,261	$ 110,631	5.00	20.00%	$ 77,441	$ 77,441	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment	$ 1,059,248	$ 894,077	$ 165,171	$ 52,113	$ 191,228	5.00	20.00%	$ 38,246	$ 43,455	-$ 5,210
1930	Transportation Equipment	$ 6,846,247	$ 1,672,924	$ 5,173,323	$ 375,989	$ 5,361,318	8.00	12.50%	$ 670,165	$ 693,664	-$ 23,499
1930	Transportation Equipment	$ 249,386	$ 168,829	$ 80,557	$ -	$ 80,557	8.00	12.50%	$ 10,070	$ 10,070	-$ 0
1935	Stores Equipment	$ 64,072	$ 28,952	$ 35,120	$ -	$ 35,120	10.00	10.00%	$ 3,512	$ 3,512	$ -
1940	Tools, Shop & Garage Equipment	$ 772,798	$ 242,019	$ 530,779	$ 70,533	$ 566,046	10.00	10.00%	$ 56,605	$ 59,229	-$ 2,624
1940	Tools, Shop & Garage Equipment - Smart Meter			$ -	$ 3,728	$ 1,864	10.00	10.00%	$ 1,274	$ 1,274	$ -
1945	Measurement & Testing Equipment	$ 866,731	$ 635,323	$ 231,408	$ 96,435	$ 279,626	10.00	10.00%	$ 27,963	$ 32,783	-$ 4,820
1950	Power Operated Equipment	$ 783,695	$ 260,735	$ 522,960	$ 54,068	$ 549,994	10.00	10.00%	$ 54,999	$ 57,705	-$ 2,706
1955	Communications Equipment	$ 173,729	$ 5,554	$ 168,175		$ 168,175	10.00	10.00%	$ 16,818	$ 16,819	-$ 2
1955	Communication Equipment (Smart Meters)			$ -	$ 696,107	$ 348,054	10.00	10.00%	$ 254,934	$ 254,934	$ -
1960	Miscellaneous Equipment	$ 98,856	$ 24,205	$ 74,651		$ 74,651	5.00	20.00%	$ 14,930	$ 14,930	$ 0
1970	Load Management Controls - Customer Premises			$ -		$ -	25.00	4.00%	$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -	25.00	4.00%	$ -		$ -
1980	System Supervisor Equipment	$ 1,507,244	$ 5,771	$ 1,501,473		$ 1,501,473	25.00	4.00%	$ 60,059	$ 60,057	$ 2
1980	System Supervisor Equipment	$ 59,236		$ 59,236		$ 59,236	15.00	6.67%	$ 3,949	$ 3,949	$ 0
1985	Miscellaneous Fixed Assets			$ -		$ -	25.00	4.00%	$ -		$ -
1990	Other Tangible Property			$ -		$ -	25.00	4.00%	$ -		$ -
1995	Contributions & Grants	-$ 44,537,160		-$ 44,537,160	-$ 4,668,971	-$ 46,871,646	25.00	4.00%	-$ 1,874,866	-$ 1,968,390	$ 93,524
etc.				$ -		$ -	25.00	4.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	**$ 285,105,480**	**$ 19,979,527**	**$ 265,125,953**	**$ 26,181,805**	**$ 278,216,856**			**$ 13,427,425**	**$ 14,261,569**	**-$ 834,144**

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

Appendix 2-CO
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

Year **2012** **Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies**

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 928,633	$ 326,748	3.86	3	33.33%	$ 240,387	$ 54,458	$ 294,845	$ 349,303	-$ 54,458	$ 108,916		$ 349,303
1611	Computer Software (Formally known as Account 1925) Smart Meters	$ -	$ 518,017	2.00	5	20.00%	$ -	$ 420,712	$ 420,712	$ 420,712	$ -	$ 420,712	$ 323,407	$ 97,305
1612	Land Rights (Formally known as Account 1906)	$ 12,879	$ -	4.85	50	2.00%	$ 2,653	$ -	$ 2,653	$ 2,653	$ 0	$ -		$ 2,653
1805	Land	$ 2,339,959		-		0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings - Structure	$ 7,099,490	$ 4,769	38.10	50	2.00%	$ 186,336	$ 48	$ 186,383	$ 186,431	-$ 48	$ 95		$ 186,400
1808	Buildings - Roof	$ 144,989		5.20	20	5.00%	$ 27,874	$ -	$ 27,874	$ 27,874	-$ 0	$ -	$ 10,745	$ 17,100
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	$ 15,658,086	$ 78,477	40.27	50	2.00%	$ 388,780	$ 785	$ 389,565	$ 390,350	-$ 785	$ 1,570		$ 390,300
1815	Transformer Station Equipment >50 kV 40 yrs	$ 24,475,179		29.21	40	2.50%	$ 837,825	$ -	$ 837,825	$ 837,825	-$ 0	$ -		$ 837,800
1815	Transformer Station Equipment >50 kV 25 yrs	$ 887,028		9.38	25	4.00%	$ 94,545	$ -	$ 94,545	$ 94,545	$ 0	$ -	$ 9,621	$ 84,900
1815	Transformer Station Equipment >50 kV 20 yrs	$ 392,015	$ 25,270	5.96	20	5.00%	$ 65,766	$ 632	$ 66,398	$ 67,030	-$ 632	$ 1,264	$ 18,546	$ 48,500
1815	Transformer Station Equipment >50 kV 15 yrs	$ 1,087,574	$ 68,590	3.92	15	6.67%	$ 277,741	$ 2,286	$ 280,028	$ 282,314	-$ 2,286	$ 4,573	$ 133,265	$ 149,000
1820	Distribution Station Equipment <50 kV 50 yrs	$ 288,917		32.78	50	2.00%	$ 8,813	$ -	$ 8,813	$ 8,813	-$ 0	$ -		$ 8,800
1820	Distribution Station Equipment <50 kV 40 yrs	$ 545,044		21.37	40	2.50%	$ 25,509	$ -	$ 25,509	$ 25,509	$ 0	$ -		$ 25,500
1820	Distribution Station Equipment <50 kV 25 yrs	$ 19,153		4.92	25	4.00%	$ 3,895	$ -	$ 3,895	$ 3,895	-$ 0	$ -	$ 1,089	$ 2,800
1820	Distribution Station Equipment <50 kV 20 yrs	$ 8,761		2.05	20	5.00%	$ 4,284	$ -	$ 4,284	$ 4,284	$ 0	$ -	$ 3,210	$ 1,100
1820	Distribution Station Equipment <50 kV 15 yrs	$ 25,299		1.90	15	6.67%	$ 13,339	$ -	$ 13,339	$ 13,339	-$ 0	$ -	$ 11,546	$ 1,800
1825	Storage Battery Equipment	$ -		-		0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 17,028,401	$ 2,587,380	31.80	40	2.50%	$ 535,489	$ 32,342	$ 567,831	$ 600,173	-$ 32,342	$ 64,685		$ 600,200
1835	Overhead Conductors & Devices	$ 14,319,062	$ 1,849,156	51.16	60	1.67%	$ 279,881	$ 15,410	$ 295,290	$ 310,700	-$ 15,410	$ 30,819		$ 310,700
1835	Overhead Devices	$ 1,591,006	$ 156,884	31.19	40	2.50%	$ 51,004	$ 1,961	$ 52,965	$ 54,926	-$ 1,961	$ 3,922		$ 54,900
1835	Voltage Regulators	$ 163,109		20.00	30	3.33%	$ 8,155	$ -	$ 8,155	$ 8,155	$ 0	$ -		$ 8,200
1835	Capicitor Banks	$ 618,096		19.36	25	4.00%	$ 31,924	$ -	$ 31,924	$ 31,924	$ 0	$ -		$ 31,900
1840	Underground Conduit	$ 12,527,558	$ 1,775,167	51.70	60	1.67%	$ 242,295	$ 14,793	$ 257,088	$ 271,881	-$ 14,793	$ 29,586		$ 271,900
1845	Underground Conductors & Devices - PILC	$ 414,000	$ 71,811	58.00	60	1.67%	$ 7,138	$ 598	$ 7,737	$ 8,335	-$ 598	$ 1,197		$ 8,300
1845	Underground Cables	$ 15,726,653	$ 2,004,581	28.66	40	2.50%	$ 548,637	$ 25,057	$ 573,695	$ 598,752	-$ 25,057	$ 50,115		$ 598,800
1845	Underground Devices	$ 1,747,406	$ 123,332	28.66	40	2.50%	$ 60,960	$ 1,542	$ 62,501	$ 64,043	-$ 1,542	$ 3,083		$ 64,000
1850	Line Transformers - Overhead	$ 15,713,834	$ 975,364	28.18	40	2.50%	$ 557,616	$ 12,192	$ 569,808	$ 582,000	-$ 12,192	$ 24,384		$ 582,000
1850	Line Transformers - Network	$ 5,503	$ 152,267	12.35	40	2.50%	$ 445	$ 1,903	$ 2,349	$ 4,252	-$ 1,903	$ 3,807		$ 4,300
1850	Line Transformers - Vault	$ -	$ 2,629	-	60	1.67%	$ -	$ 22	$ 22	$ 44	-$ 22	$ 44		$ 44
1850	Line Transformers - Roof	$ 497,948		23.45	30	3.33%	$ 21,235	$ -	$ 21,235	$ 21,235	-$ 0	$ -		$ 21,200
1850	Line Transformers - Network Protectors	$ 91,592	$ 107,832	40.67	40	2.50%	$ 2,252	$ 1,348	$ 3,600	$ 4,948	-$ 1,348	$ 2,696		$ 4,900
1850	Line Transformers - Padmount	$ 3,991,872	$ 721,460	35.16	40	2.50%	$ 113,523	$ 9,018	$ 122,542	$ 131,560	-$ 9,018	$ 18,037		$ 131,600
1850	Line Transformers - Submersible	$ 3,195,923	$ 790,096	25.06	30	3.33%	$ 127,552	$ 13,168	$ 140,721	$ 153,889	-$ 13,168	$ 26,337		$ 153,900
1850	Line Transformers - Foundation	$ 1,427,416	$ 417,525	59.55	60	1.67%	$ 23,971	$ 3,479	$ 27,451	$ 30,930	-$ 3,479	$ 6,959		$ 30,900
1855	Services - Overhead	$ 1,887,729	$ 419,374	52.20	60	1.67%	$ 36,163	$ 3,495	$ 39,658	$ 43,153	-$ 3,495	$ 6,990		$ 43,200
1855	Services - Underground	$ 22,543,287	$ 2,054,280	31.40	40	2.50%	$ 717,938	$ 25,679	$ 743,616	$ 769,295	-$ 25,679	$ 51,357		$ 769,300
1860	Meters - Stranded	$ 5,123,923	-$ 2,838,532	6.76	25	4.00%	$ 757,552	-$ 56,771	$ 700,781	$ 644,011	$ 56,770	-$ 113,541	$ 559,700	$ 84,300
1860	Meters (Smart Meters)	$ -	$ 97,421	2.98	15	6.67%	$ -	$ 3,247	$ 3,247	$ 6,495	-$ 3,248	$ 6,495		$ 6,500
1860	Meters (Smart Meters Decision)	$ -	$ 11,943,758	2.98	15	6.67%	$ -	$ 2,381,184	$ 2,381,184	$ 2,381,184	$ -	$ 2,381,184	$ 1,584,933	$ 796,251
1905	Land	$ 1,395,300		-		0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures - Building	$ 5,262,681	$ 30,105	29.73	50	2.00%	$ 176,987	$ 301	$ 177,288	$ 177,589	-$ 301	$ 602		$ 177,600
1908	Buildings & Fixtures - Roof	$ 1,567,291		6.36	20	5.00%	$ 246,333	$ -	$ 246,333	$ 246,333	-$ 0	$ -		$ 246,300
1910	Leasehold Improvements	$ -		-		0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 340,212	$ 34,301	5.49	10	10.00%	$ 61,923	$ 1,715	$ 63,638	$ 65,353	-$ 1,715	$ 3,430	$ 16,660	$ 48,700
1915	Office Furniture & Equipment (5 years)	$ -		-	5	20.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 350,465	$ 227,721	3.64	5	20.00%	$ 96,316	$ 22,772	$ 119,088	$ 141,860	-$ 22,772	$ 45,544	$ 24,355	$ 117,500
1920	Computer Equip.-Hardware - Smart Meters	$ -	$ 221,261	-	5	20.00%	$ -	$ 77,441	$ 77,441	$ 77,441	$ -	$ 77,441		$ 77,441
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		-		0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 2,455,998	$ 330,475	6.77	10	10.00%	$ 362,748	$ 16,524	$ 379,271	$ 395,795	-$ 16,524	$ 33,048		$ 395,800
1930	Transportation Equipment	$ 325,088	$ 97,627	6.50	8	12.50%	$ 50,023	$ 6,102	$ 56,124	$ 62,226	-$ 6,102	$ 12,203		$ 62,200
1935	Stores Equipment	$ 21,484		6.12	10	10.00%	$ 3,512	$ -	$ 3,512	$ 3,512	$ 0	$ -	-$ 500	$ 4,000
1940	Tools, Shop & Garage Equipment	$ 324,953	$ 67,580	6.19	10	10.00%	$ 52,471	$ 3,379	$ 55,850	$ 59,229	-$ 3,379	$ 6,758	$ 5,230	$ 54,000
1940	Tools, Shop & Garage Equipment Smart Meters	$ -	$ 3,728	-	10	10.00%	$ -	$ 1,274	$ 1,274	$ 1,274	$ -	$ 1,274	$ 901	$ 400
1945	Measurement & Testing Equipment	$ 163,015	$ 96,435	7.04	10	10.00%	$ 23,139	$ 4,822	$ 27,961	$ 32,783	-$ 4,822	$ 9,644	-$ 1,300	$ 34,100
1950	Power Operated Equipment	$ 306,812	$ 54,068	5.87	10	10.00%	$ 52,298	$ 2,703	$ 55,002	$ 57,705	-$ 2,703	$ 5,407	$ 3,094	$ 54,600
1955	Communications Equipment	$ 58,879		3.50	10	10.00%	$ 16,819	$ -	$ 16,819	$ 16,818	$ 1	$ -	-$ 3,489	$ 20,300
1955	Communication Equipment (Smart Meters)	$ -	$ 696,107	-	10	10.00%	$ -	$ 254,934	$ 254,934	$ 254,934	$ -	$ 254,934	$ 185,300	$ 69,600
1960	Miscellaneous Equipment	$ 40,970		2.74	5	20.00%	$ 14,931	$ -	$ 14,931	$ 14,931	-$ 0	$ -	$ 200	$ 14,700

Appendix 2-CO
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

Year 2012 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1970	Load Management Controls - Customer Premises	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment	$ 115,074		1.20	25	4.00%	$ 95,928	$ -	$ 95,928	$ 95,928	-$ 0	$ -	$ 91,867	$ 4,100
1985	Miscellaneous Fixed Assets	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1990	Other Tangible Property	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	**Contributions & Grants**					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	-$ 1,626,853	-$ 600,093	34.26	40	2.50%	-$ 47,485	-$ 7,501	-$ 54,986	-$ 62,487	$ 7,501	-$ 15,002		-$ 62,500
1995	Contributed Capital - Overhead Conductors	-$ 1,246,129	-$ 607,123	51.53	60	1.67%	-$ 24,183	-$ 5,059	-$ 29,243	-$ 34,302	$ 5,059	-$ 10,119		-$ 34,300
1995	Contributed Capital - Overhead Devices	-$ 138,459	-$ 67,458	51.54	40	2.50%	-$ 2,687	-$ 843	-$ 3,530	-$ 4,373	$ 843	-$ 1,686		-$ 4,400
1995	Contributed Capital - Overhead Services	-$ 1,243,014	$ 90,988	23.29	60	1.67%	-$ 53,378	$ 758	-$ 52,620	-$ 51,862	-$ 758	$ 1,516		-$ 51,900
1995	Contributed Capital - U/G Trenching & Ductwork	-$ 5,566,404	-$ 1,079,357	46.38	60	1.67%	-$ 120,025	-$ 8,995	-$ 129,019	-$ 138,014	$ 8,995	-$ 17,989		-$ 138,000
1995	Contributed Capital - U/G Cables	-$ 2,292,136	-$ 1,393,554	65.48	40	2.50%	-$ 35,006	-$ 17,419	-$ 52,426	-$ 69,845	$ 17,419	-$ 34,839		-$ 69,800
1995	Contributed Capital - U/G Devices	-$ 254,682	-$ 104,668	42.07	40	2.50%	-$ 6,054	-$ 1,308	-$ 7,363	-$ 8,671	$ 1,308	-$ 2,617		-$ 8,700
1995	Contributed Capital - Overhead Transformers	-$ 2,739,500	-$ 48,024	29.34	40	2.50%	-$ 93,367	-$ 600	-$ 93,968	-$ 94,568	$ 600	-$ 1,201		-$ 94,600
1995	Contributed Capital - U/G Padmount Transformers	-$ 1,946,718	-$ 317,706	31.32	40	2.50%	-$ 62,160	-$ 3,971	-$ 66,132	-$ 70,103	$ 3,971	-$ 7,943		-$ 70,100
1995	Contributed Capital - U/G Submersible Transformers	-$ 1,865,435	-$ 281,562	33.72	30	3.33%	-$ 55,322	-$ 4,693	-$ 60,014	-$ 64,707	$ 4,693	-$ 9,385		-$ 64,700
1995	Contributed Capital - U/G Services	-$ 13,406,324	$ 172,272	34.37	40	2.50%	-$ 390,069	$ 2,153	-$ 387,915	-$ 385,762	-$ 2,153	$ 4,307		-$ 385,800
1995	Contributed Capital - Transfomer Foundations	-$ 795,151	-$ 429,058	58.25	60	1.67%	-$ 13,651	-$ 3,575	-$ 17,227	-$ 20,802	$ 3,575	-$ 7,151		-$ 20,800
1995	Contributed Capital - Meters	-$ 166,183	-$ 95,090	10.21	15	6.67%	-$ 16,271	-$ 3,170	-$ 19,440	-$ 22,610	$ 3,170	-$ 6,339		-$ 22,600
1995	Contributed Capital - OEB Clearing	$ 68,538	$ 91,462	44.84	15	6.67%	$ 1,529	$ 3,049	$ 4,577	$ 7,626	-$ 3,049	$ 6,097		$ 7,600
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	**$ 152,037,096**	**$ 21,624,093**				**$ 6,636,777**	**$ 3,309,380**	**$ 9,946,158**	**$ 10,119,993**	**-$ 173,835**	**$ 3,483,216**	**$ 2,978,379**	**$ 7,141,297**
										10,119,993				

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

3 The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with the Board's regulatory accounting policies. The capitalization and depreciation expense accounting changes should be implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, the Kinectrics Report, and the Revised 2012 Accounting Procedures Handbook for Electricity Distributors ("APH").

4 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2012 additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1, 2012, the effective date of the changes in policies, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as of January 1, 2012. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as of January 1, 2012.

5 NBV must exclude assets still on the books but which have been fully amortized or depreciated.

6 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

Appendix 2-CP
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

2013 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Deprecation + ((d)*0.5)/(f)	2013 Depreciation Expense per Apppendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [3] (p) = 2012 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 594,000	5	20.00%	$ 408,702	$ 380,495	$ 28,207	$ 118,800		$ 468,100
1611	Computer Software (Formally known as Account 1925) - Smart Meters	$ -	5	20.00%	$ 97,305	$ 97,305	$ -	$ -	$ 97,305	$ -
1612	Land Rights (Formally known as Account 1906)		50	2.00%	$ 2,653	$ 2,653	$ 0	$ -		$ 2,653
1805	Land		-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	$ 500,000	50	2.00%	$ 191,400	$ 186,400	$ 5,000	$ 10,000		$ 196,400
1808	Buildings - Roof	$ -	20	5.00%	$ 17,100	$ 17,100	$ -	$ -	$ 4,480	$ 12,600
1810	Leasehold Improvements		-	0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	$ 700,000	50	2.00%	$ 397,300	$ 404,300	-$ 7,000	$ 14,000		$ 404,300
1815	Transformer Station Equipment >50 kV 40 yrs	$ 1,000,000	40	2.50%	$ 850,300	$ 862,800	-$ 12,500	$ 25,000		$ 862,800
1815	Transformer Station Equipment >50 kV 25 yrs	$ 263,300	25	4.00%	$ 90,200	$ 95,500	-$ 5,300	$ 10,500	$ 8,807	$ 86,600
1815	Transformer Station Equipment >50 kV 20 yrs		20	5.00%	$ 48,500	$ 48,500	$ -	$ -	$ 6,398	$ 42,100
1815	Transformer Station Equipment >50 kV 15 yrs	$ 133,400	15	6.67%	$ 153,400	$ 157,900	-$ 4,500	$ 8,900	$ 12,271	$ 145,600
1820	Distribution Station Equipment <50 kV 50 yrs		50	2.00%	$ 8,800	$ 8,800	$ -	$ -		$ 8,800
1820	Distribution Station Equipment <50 kV 40 yrs		40	2.50%	$ 25,500	$ 25,500	$ -	$ -		$ 25,500
1820	Distribution Station Equipment <50 kV 25 yrs		25	4.00%	$ 2,800	$ 2,800	$ -	$ -		$ 2,800
1820	Distribution Station Equipment <50 kV 20 yrs		20	5.00%	$ 1,100	$ 1,100	$ -	$ -		$ 1,100
1820	Distribution Station Equipment <50 kV 15 yrs	$ 63,000	15	6.67%	$ 3,900	$ 6,000	-$ 2,100	$ 4,200		$ 6,000
1825	Storage Battery Equipment		-	0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 2,718,300	40	2.50%	$ 634,200	$ 668,185	-$ 33,985	$ 68,000		$ 668,200
1835	Overhead Conductors	$ 1,636,400	60	1.67%	$ 324,337	*$ 337,973*	-$ 13,636	$ 27,273		$ 338,000
1835	Overhead Devices	$ 181,900	40	2.50%	$ 57,174	*$ 59,497*	-$ 2,323	$ 4,548		$ 59,400
1835	Voltage Regulators		30	3.33%	$ 8,200	$ 8,200	$ -	$ -		$ 8,200
1835	Capacitor Banks		25	4.00%	$ 31,900	$ 31,900	$ -	$ -		$ 31,900
1840	Underground Conduit	$ 3,191,900	60	1.67%	$ 298,499	$ 325,075	-$ 26,576	$ 53,198		$ 325,100
1845	Underground Conductors & Devices - PILC		60	1.67%	$ 8,300	$ 8,300	$ -	$ -		$ 8,300
1845	Underground Cables	$ 2,076,700	40	2.50%	$ 624,759	$ 650,698	-$ 25,939	$ 51,918		$ 650,718
1845	Underground Devices	$ 230,700	40	2.50%	$ 66,884	$ 69,800	-$ 2,916	$ 5,768		$ 69,768
1850	Overhead Line Transformers	$ 788,300	40	2.50%	$ 591,854	$ 601,708	-$ 9,854	$ 19,708		$ 601,708
1850	Network Transformers	$ 255,900	40	2.50%	$ 7,499	$ 10,700	-$ 3,201	$ 6,398		$ 10,698
1850	Vault	$ 85,400	60	1.67%	$ 755	$ 1,501	-$ 746	$ 1,423		$ 1,467
1850	Roof		30	3.33%	$ 21,200	$ 21,200	$ -	$ -		$ 21,200
1850	Network Protectors		40	2.50%	$ 4,900	$ 4,900	$ -	$ -		$ 4,900
1850	Padmount Transformers	$ 120,600	40	2.50%	$ 133,108	$ 134,688	-$ 1,581	$ 3,015		$ 134,600
1850	Submersible Transformers	$ 1,307,100	30	3.33%	$ 175,685	$ 197,459	-$ 21,774	$ 43,570		$ 197,500
1850	Transformer Foundations	$ 386,300	60	1.67%	$ 34,119	$ 37,369	-$ 3,249	$ 6,438		$ 37,300
1855	Services - Overhead	$ 340,600	60	1.67%	$ 46,038	$ 48,830	-$ 2,792	$ 5,677		$ 48,900
1855	Services - Underground	$ 1,798,100	40	2.50%	$ 791,776	$ 814,305	-$ 22,529	$ 44,953		$ 814,300
1860	Meters	$ 690,000	25	4.00%	$ 98,100	$ 115,491	-$ 17,391	$ 27,600		$ 111,900
1860	Meters (Smart Meters)		15	6.67%	$ 6,500	$ 6,500	$ -	$ -		$ 6,500
1860	Meters (Smart Meters Decision)		15	6.67%	$ 796,251	$ 796,251	$ -	$ -		$ 796,251
1905	Land		-	0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures - Structure	$ 5,600,000	50	2.00%	$ 233,600	$ 289,600	-$ 56,000	$ 112,000		$ 289,600
1908	Buildings & Fixtures - Roof	$ 60,000	20	5.00%	$ 247,800	$ 249,300	-$ 1,500	$ 3,000		$ 249,300
1910	Leasehold Improvements		-	0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 126,600	10	10.00%	$ 55,030	$ 61,400	-$ 6,370	$ 12,660		$ 61,360
1915	Office Furniture & Equipment (5 years)		5	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 145,000	5	20.00%	$ 132,000	$ 91,548	$ 40,452	$ 29,000		$ 146,500
1920	Computer Equip.-Hardware(Post Mar. 22/04)		5	20.00%	$ 77,441	$ 77,441	$ -	$ -		$ 77,400

Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

2013 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Deprecation + ((d)*0.5)/(f)	2013 Depreciation Expense per Apppendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [3] (p) = 2012 Full Year Depreciation + (n) - (o)
1920	Computer Equip.-Hardware(Post Mar. 19/07)		5	20.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,004,200	10	10.00%	$ 446,010	$ 464,700	-$ 18,690	$ 100,420		$ 496,200
1930	Transportation Equipment	$ 120,000	8	12.50%	$ 69,700	$ 71,000	-$ 1,300	$ 15,000		$ 77,200
1935	Stores Equipment		10	10.00%	$ 4,000	$ 4,000	$ -	$ -		$ 4,000
1940	Tools, Shop & Garage Equipment	$ 88,400	10	10.00%	$ 58,420	$ 62,810	-$ 4,390	$ 8,840		$ 62,840
1940	Tools - Smart Meters		10	10.00%	$ 400	$ 400	$ -	$ -		$ 400
1945	Measurement & Testing Equipment		10	10.00%	$ 34,100	$ 34,100	$ -	$ -		$ 34,100
1950	Power Operated Equipment		10	10.00%	$ 54,600	$ 54,600	$ -	$ -		$ 54,600
1955	Communications Equipment		10	10.00%	$ 20,300	$ 20,300	$ -	$ -		$ 20,300
1955	Communication Equipment (Smart Meters)		10	10.00%	$ 69,600	$ 69,600	$ -	$ -		$ 69,600
1960	Miscellaneous Equipment		5	20.00%	$ 14,700	$ 14,700	$ -	$ -	$ 3,383	$ 11,300
1970	Load Management Controls - Customer Premises		5	20.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises		5	20.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment		25	4.00%	$ 4,100	$ 4,100	$ -	$ -		$ 4,100
1985	Miscellaneous Fixed Assets		10	10.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -	$ -	$ -	$ -		$ -
1995	***Contributions & Grants***			0.00%	$ -		$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	-$ 308,400	40	2.50%	-$ 66,355	-$ 70,198	$ 3,843	-$ 7,710		-$ 70,210
1995	Contributed Capital - Overhead Conductors	-$ 212,130	60	1.67%	-$ 36,068	-$ 37,838	$ 1,770	-$ 3,536		-$ 37,836
1995	Contributed Capital - Overhead Devices	-$ 23,570	40	2.50%	-$ 4,695	-$ 4,963	$ 268	-$ 589		-$ 4,989
1995	Contributed Capital - Overhead Services	-$ 31,750	60	1.67%	-$ 52,165	-$ 32,688	-$ 19,477	-$ 529		-$ 52,429
1995	Contributed Capital - U/G Trenching & Ductwork	-$ 797,000	60	1.67%	-$ 144,642	-$ 134,448	-$ 10,193	-$ 13,283		-$ 151,283
1995	Contributed Capital - U/G Cables	-$ 623,160	40	2.50%	-$ 77,590	-$ 117,647	$ 40,057	-$ 15,579		-$ 85,379
1995	Contributed Capital - U/G Devices	-$ 69,240	40	2.50%	-$ 9,566	-$ 11,818	$ 2,252	-$ 1,731		-$ 10,431
1995	Contributed Capital - Overhead Transformers	$ -	40	2.50%	-$ 94,600	-$ 86,383	-$ 8,217	$ -		-$ 94,600
1995	Contributed Capital - U/G Padmount Transformers	-$ 141,200	40	2.50%	-$ 71,865	-$ 73,632	$ 1,767	-$ 3,530		-$ 73,630
1995	Contributed Capital - U/G Submersible Transformers	-$ 329,400	30	3.33%	-$ 70,190	-$ 77,921	$ 7,731	-$ 10,980		-$ 75,680
1995	Contributed Capital - U/G Services	-$ 1,303,150	40	2.50%	-$ 402,089	-$ 415,534	$ 13,444	-$ 32,579		-$ 418,379
1995	Contributed Capital - Transfomer Foundations	-$ 96,500	60	1.67%	-$ 21,604	-$ 34,084	$ 12,480	-$ 1,608		-$ 22,408
1995	Contributed Capital - Meters	-$ 40,000	15	6.67%	-$ 23,933	-$ 28,787	$ 4,853	-$ 2,667		-$ 25,267
1995	Contributed Capital - OEB Clearing	$ 40,000	15	6.67%	$ 8,933	$ 13,709	-$ 4,776	$ 2,667		$ 10,267
etc.					$ -		$ -	$ -		$ -
					$ -		$ -	$ -		$ -
	Total	**$ 22,270,600**			**$ 7,516,372**	**$ 7,705,052**	**-$ 188,680**	**$ 750,151**	**$ 132,644**	**$ 7,758,707**

Appendix 2-CQ
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

2014 **Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies**

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Depreciation + ((d)*0.5)/(f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 540,000	5	20.00%	$ 522,100	$ 666,800	-$ 144,700
1611	Computer Software (Formally known as Account 1925) - Smart Meters		5	20.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)		50	2.00%	$ 2,653	$ 2,653	$ 0
1805	Land			0.00%	$ -	$ -	$ -
1808	Buildings - Structure	$ 158,000	50	2.00%	$ 197,980	$ 186,400	$ 11,580
1808	Buildings - Roof	$ 3,200	20	5.00%	$ 12,680	$ 12,700	-$ 20
1810	Leasehold Improvements			0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV 50yrs	$ 650,000	50	2.00%	$ 410,800	$ 411,100	-$ 300
1815	Transformer Station Equipment >50 kV 40yrs	$ 1,390,000	40	2.50%	$ 880,175	$ 881,000	-$ 825
1815	Transformer Station Equipment >50 kV 25 yrs		25	4.00%	$ 86,600	$ 87,300	-$ 700
1815	Transformer Station Equipment >50 kV 20 yrs		20	5.00%	$ 42,100	$ 41,500	$ 600
1815	Transformer Station Equipment >50 kV 15 yrs		15	6.67%	$ 145,601	$ 146,000	-$ 399
1820	Distribution Station Equipment <50 kV 50 yrs		50	2.00%	$ 8,800	$ 8,800	$ -
1820	Distribution Station Equipment <50 kV 40 yrs		40	2.50%	$ 25,500	$ 25,500	$ -
1820	Distribution Station Equipment <50 kV 25 yrs		25	4.00%	$ 2,800	$ 2,200	$ 600
1820	Distribution Station Equipment <50 kV 20 yrs		20	5.00%	$ 1,100	$ 1,100	$ -
1820	Distribution Station Equipment <50 kV 15 yrs		15	6.67%	$ 6,000	$ 6,000	$ -
1825	Storage Battery Equipment			0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,768,500	40	2.50%	$ 702,806	$ 703,585	-$ 779
1835	Overhead Conductors	$ 1,997,100	60	1.67%	$ 354,643	$ 354,573	$ 70
1835	Overhead Devices	$ 221,900	40	2.50%	$ 62,174	$ 63,297	-$ 1,123
1835	Voltage Regulators		30	3.33%	$ 8,200	$ 8,200	$ -
1835	Capicitor Banks		25	4.00%	$ 31,900	$ 31,900	$ -
1840	Underground Conduit	$ 2,820,500	60	1.67%	$ 348,604	$ 348,575	$ 29
1845	Underground Conductors & Devices - PILC		60	1.67%	$ 8,300	$ 8,300	$ -
1845	Underground Cables	$ 2,359,600	40	2.50%	$ 680,213	$ 680,198	$ 15
1845	Underground Devices	$ 262,200	40	2.50%	$ 73,045	$ 73,100	-$ 55
1850	Overhead Line Transformers	$ 820,800	40	2.50%	$ 611,968	$ 611,983	-$ 16
1850	Network Transformers	$ 192,100	40	2.50%	$ 13,099	$ 13,000	$ 99
1850	Vault		60	1.67%	$ 1,467	$ 1,500	-$ 33
1850	Roof		30	3.33%	$ 21,200	$ 20,900	$ 300
1850	Network Protectors		40	2.50%	$ 4,900	$ 4,900	$ -
1850	Padmount	$ 463,000	40	2.50%	$ 140,388	$ 140,360	$ 28
1850	Submersible	$ 1,097,700	30	3.33%	$ 215,795	$ 215,856	-$ 61
1850	Foundation	$ 324,900	60	1.67%	$ 40,008	$ 40,125	-$ 118
1855	Services - Overhead	$ 538,500	60	1.67%	$ 53,388	$ 53,387	$ 1
1855	Services - Underground	$ 2,525,500	40	2.50%	$ 845,869	$ 845,749	$ 120
1860	Meters	$ 779,600	25	4.00%	$ 127,492	$ 126,091	$ 1,401
1860	Meters (Smart Meters)		15	6.67%	$ 6,500	$ 6,500	$ -
1860	Meters (Smart Meters Decision)		15	6.67%	$ 796,251	$ 796,251	$ -
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures - Structure	$ 1,350,000	50	2.00%	$ 303,100	$ 309,400	-$ 6,300
1908	Buildings & Fixtures - Roof		20	5.00%	$ 249,300	$ 243,200	$ 6,100
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 70,000	10	10.00%	$ 64,860	$ 75,800	-$ 10,940
1915	Office Furniture & Equipment (5 years)		5	20.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 180,000	5	20.00%	$ 164,500	$ 126,200	$ 38,300
1920	Computer Equip.-Hardware(Post Mar. 22/04)		5	20.00%	$ 77,400	$ 77,400	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment	$ 840,000	10	10.00%	$ 538,200	$ 559,500	-$ 21,300
1930	Transportation Equipment	$ 80,000	8	12.50%	$ 82,200	$ 83,500	-$ 1,300
1935	Stores Equipment		10	10.00%	$ 4,000	$ 4,000	$ -
1940	Tools, Shop & Garage Equipment	$ 90,000	10	10.00%	$ 67,340	$ 71,800	-$ 4,460
1940	Tools - Smart Meters		10	10.00%	$ 400	$ 400	$ -
1945	Measurement & Testing Equipment		10	10.00%	$ 34,100	$ 34,100	$ -
1950	Power Operated Equipment		10	10.00%	$ 54,600	$ 54,600	$ -
1955	Communications Equipment		10	10.00%	$ 20,300	$ 20,200	$ 100
1955	Communication Equipment (Smart Meters)		10	10.00%	$ 69,600	$ 69,600	$ -
1960	Miscellaneous Equipment		10	10.00%	$ 11,300	$ 11,300	$ -
1970	Load Management Controls - Customer Premises		5	20.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -	$ -	$ -

Appendix 2-CQ
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

2014 **Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies**

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Depreciation + ((d)*0.5)/(f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1980	System Supervisor Equipment		25	4.00%	$ 4,100	$ 4,100	$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -	$ -	$ -
1990	Other Tangible Property			0.00%	$ -	$ -	$ -
1995	***Contributions & Grants***			0.00%	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	-$ 500,500	40	2.50%	-$ 76,466	-$ 76,485	$ 19
1995	Contributed Capital - Overhead Conductors	-$ 411,840	60	1.67%	-$ 41,268	-$ 41,283	$ 16
1995	Contributed Capital - Overhead Devices	-$ 45,760	40	2.50%	-$ 5,561	-$ 5,487	-$ 74
1995	Contributed Capital - Overhead Services	-$ 78,650	60	1.67%	-$ 53,085	-$ 33,375	-$ 19,710
1995	Contributed Capital - Underground Trenching & Ductwork	-$ 815,625	60	1.67%	-$ 158,080	-$ 141,275	-$ 16,805
1995	Contributed Capital - Underground Cables	-$ 700,583	40	2.50%	-$ 94,136	-$ 126,428	$ 32,292
1995	Contributed Capital - Underground Devices	-$ 77,843	40	2.50%	-$ 11,404	-$ 12,770	$ 1,366
1995	Contributed Capital - Overhead Transformer	$ -	40	2.50%	-$ 94,600	-$ 86,383	-$ 8,217
1995	Contributed Capital - Underground Padmount Transformer	-$ 134,868	40	2.50%	-$ 75,316	-$ 75,360	$ 44
1995	Contributed Capital -Underground Submersible Transformer	-$ 314,700	30	3.33%	-$ 80,925	-$ 83,156	$ 2,231
1995	Contributed Capital - Underground Services	-$ 1,537,000	40	2.50%	-$ 437,591	-$ 434,761	-$ 2,830
1995	Contributed Capital - Transformer Foundations	-$ 92,200	60	1.67%	-$ 23,177	-$ 34,825	$ 11,648
1995	Contributed Capital - Meters	-$ 40,000	15	6.67%	-$ 26,600	-$ 26,580	-$ 20
1995	Contributed Capital - OEB Clearing	-$ 87,900	15	6.67%	$ 7,337	$ 11,538	-$ 4,201
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	**$ 17,685,631**			**$ 8,067,524**	**$ 8,205,853**	**-$ 138,329**
	Total Depreciation expense to be included in the test year revenue requirement				**$ 8,067,524**		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

Appendix 2-ED
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2017	2018
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
			$	$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1			152,037,099	165,753,427					
Net Additions - Note 4			21,275,856	18,621,591					
Net Depreciation (amounts should be negative) - Note 4			-7,559,528	-11,968,981					
Closing net PP&E (1)			165,753,427	172,406,037					
PP&E Values under revised CGAAP (Starts from 2012)									
Opening net PP&E - Note 1			152,037,099	168,018,818					
Net Additions - Note 4			19,399,675	17,657,712					
Net Depreciation (amounts should be negative) - Note 4			-3,417,956	-7,305,052					
Closing net PP&E (2)			168,018,818	178,371,478					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-2,265,391	-5,965,441					

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	- 5,965,441	**WACC**	5.99%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 1,429,320	**# of years of rate rider disposition period**	4
Amount included in Deferral and Variance Account Rate Rider Calculation	- 7,394,761		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2012, the PP&E values as of January 1, 2012 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account opening balance as of 2014 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

Appendix 2-FA

Renewable Generation Connection Investment Summary (over the rate setting period)

Enter the details of the Renewable Generation Connection projects as described in Section 2.5.2.5 of the Filing Requirements.

All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB

For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.

Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (pg 15, EB-2009-0349)

Part A

REI Investments (Direct Benefit at 6%)	2014	2015	2016	2017	2018
Project 1					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$37,405	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ 37,405**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Part B

Expansion Investments (Direct Benefit at 17%)	2014	2015	2016	2017	2018
Project 1					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014 Test Year			2015			2016			2017			2018		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ 116,347	$ 6,981	$ 109,366	$ 113,069	$ 6,784	$ 106,285	$ 109,792	$ 6,588	$ 103,204	$ 106,515	$ 6,391	$ 100,124	$ 103,237	$ 6,194	$ 97,043
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$37,405	$ 2,244	$ 35,161	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13%		$ 292	$ 4,571		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 7,273	$ 113,937		$ 6,784	$ 106,285		$ 6,588	$ 103,204		$ 6,391	$ 100,124		$ 6,194	$ 97,043
Deemed ST Debt	4%		$ 291	$ 4,557		$ 271	$ 4,251		$ 264	$ 4,128		$ 256	$ 4,005		$ 248	$ 3,882
Deemed LT Debt	56%		$ 4,073	$ 63,805		$ 3,799	$ 59,520		$ 3,689	$ 57,795		$ 3,579	$ 56,069		$ 3,469	$ 54,344
Deemed Equity	40%		$ 2,909	$ 45,575		$ 2,714	$ 42,514		$ 2,635	$ 41,282		$ 2,556	$ 40,050		$ 2,478	$ 38,817
ST Interest	4.13%		$ 12	$ 188		$ 11	$ 176		$ 11	$ 170		$ 11	$ 165		$ 10	$ 160
LT Interest	2.07%		$ 84	$ 1,321		$ 79	$ 1,232		$ 76	$ 1,196		$ 74	$ 1,161		$ 72	$ 1,125
ROE	8.98%		$ 261	$ 4,093		$ 244	$ 3,818		$ 237	$ 3,707		$ 230	$ 3,596		$ 222	$ 3,486
Cost of Capital Total			$ 358	$ 5,602		$ 334	$ 5,225		$ 324	$ 5,074		$ 314	$ 4,923		$ 305	$ 4,771
OM&A			$ 2,244	$ 35,161		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 3,277	$ 197	$ 3,081	$ 3,277	$ 197	$ 3,081	$ 3,277	$ 197	$ 3,081	$ 3,277	$ 197	$ 3,081	$ 3,277	$ 197	$ 3,081
Grossed-up PILs			-$ 1,161	-$ 18,192		-$ 454	-$ 7,106		-$ 132	-$ 2,064		$ 14	$ 222		$ 80	$ 1,260
Revenue Requirement			$ 1,637	$ 25,651		$ 77	$ 1,200		$ 389	$ 6,091		$ 525	$ 8,225		$ 582	$ 9,112
Provincial Rate Protection				$ 25,651			$ 1,200			$ 6,091			$ 8,225			$ 9,112
Monthly Amount Paid by IESO				$ 2,138			$ 100			$ 508			$ 685			$ 759

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2014 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2014		2015		2016			2017			2018	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
							Total			Total		
Net Income - ROE on Rate Base	$ 261	$ 4,093	$ 244	$ 3,818	$ 237	$ 3,707		$ 230	$ 3,596		$ 222	$ 3,486
Amortization (6% DB and 94% P)	$ 197	$ 3,081	$ 197	$ 3,081	$ 197	$ 3,081		$ 197	$ 3,081		$ 197	$ 3,081
CCA (6% DB and 94% P)	-$ 3,679	-$ 57,631	-$ 1,698	-$ 26,607	-$ 799	-$ 12,512		-$ 387	-$ 6,061		-$ 196	-$ 3,072
Taxable income	-$ 3,221	-$ 50,458	-$ 1,258	-$ 19,709	-$ 365	-$ 5,724		$ 39	$ 616		$ 223	$ 3,494
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%	26.50%		26.50%	26.50%
Income Taxes Payable	-$ 853.49	-$ 13,371.35	-$ 333.38	-$ 5,222.88	-$ 96.83	-$ 1,516.93		$ 10.42	$ 163.18		$ 59.10	$ 925.93
Gross Up												
Income Taxes Payable	-$ 1,161.21	-$ 18,192.31	-$ 453.57	-$ 7,105.96	-$ 131.73	-$ 2,063.85		$ 14.17	$ 222.01		$ 80.41	$ 1,259.77
Grossed Up PILs	**-$ 1,161**	**-$ 18,192**	**-$ 454**	**-$ 7,106**	**-$ 132**	**-$ 2,064**		**$ 14**	**$ 222**		**$ 80**	**$ 1,260**

Net Fixed Assets

		2014	2015	2016	2017	2018
Enter applicable amortization in years:	36					
Opening Gross Fixed Assets		$ 107,751	$ 107,751	$ 107,751	$ 107,751	$ 107,751
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ 107,751	$ 107,751	$ 107,751	$ 107,751	$ 107,751
Opening Accumulated Amortization			$ 2,993	$ 5,986	$ 8,979	$ 11,972
Current Year Amortization (before additions)		$ 2,993	$ 2,993	$ 2,993	$ 2,993	$ 2,993
Additions (half year)		$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ 2,993	$ 5,986	$ 8,979	$ 11,972	$ 14,965
Opening Net Fixed Assets		$ 107,751	$ 104,758	$ 101,765	$ 98,772	$ 95,779
Closing Net Fixed Assets		$ 104,758	$ 101,765	$ 98,772	$ 95,779	$ 92,786
Average Net Fixed Assets		$ 106,254	$ 103,261	$ 100,268	$ 97,275	$ 94,282

UCC for PILs Calculation

		2014	2015	2016	2017	2018
Opening UCC		$ 107,751	$ 48,488	$ 21,820	$ 9,819	$ 4,418
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 107,751	$ 48,488	$ 21,820	$ 9,819	$ 4,418
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ 107,751	$ 48,488	$ 21,820	$ 9,819	$ 4,418
CCA Rate Class (to be entered)	50	50	50	50	50	50
CCA Rate (to be entered)	55%	55%	55%	55%	55%	55%
CCA		$ 59,263	$ 26,668	$ 12,001	$ 5,400	$ 2,430
Closing UCC		$ 48,488	$ 21,820	$ 9,819	$ 4,418	$ 1,988

Net Fixed Assets

		2014	2015	2016	2017	2018
Enter applicable amortization in years:	15					
Opening Gross Fixed Assets		$ 10,234	$ 10,234	$ 10,234	$ 10,234	$ 10,234
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ 10,234	$ 10,234	$ 10,234	$ 10,234	$ 10,234
Opening Accumulated Amortization			$ 284	$ 569	$ 853	$ 1,137
Current Year Amortization (before additions)		$ 284	$ 284	$ 284	$ 284	$ 284
Additions (half year)		$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ 284	$ 569	$ 853	$ 1,137	$ 1,421
Opening Net Fixed Assets		$ 10,234	$ 9,950	$ 9,665	$ 9,381	$ 9,097
Closing Net Fixed Assets		$ 9,950	$ 9,665	$ 9,381	$ 9,097	$ 8,813
Average Net Fixed Assets		$ 10,092	$ 9,808	$ 9,523	$ 9,239	$ 8,955

UCC for PILs Calculation

		2014	2015	2016	2017	2018
Opening UCC		$ 10,234	$ 8,187	$ 6,550	$ 5,240	$ 4,192
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 10,234	$ 8,187	$ 6,550	$ 5,240	$ 4,192
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ 10,234	$ 8,187	$ 6,550	$ 5,240	$ 4,192
CCA Rate Class (to be entered)	8	8	8	8	8	8
CCA Rate (to be entered)	20%	20%	20%	20%	20%	20%
CCA		$ 2,047	$ 1,637	$ 1,310	$ 1,048	$ 838
Closing UCC		$ 8,187	$ 6,550	$ 5,240	$ 4,192	$ 3,353

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	August 2012	August 2013
	Reporting Basis	CGAAP	CGAAP
4082	Retailer Services Revenue	$ 42,622	$ 33,926
4084	STR Revenue	$ 1,501	$ 986
4086	SSS Administration Charges	$ 164,228	$ 168,915
4210	Rent from Electric Property	$ 365,154	$ 511,068
4220	Other Electric Revenues	$ 18,400	$ 19,000
4225	Late Payment Charges	$ 162,939	$ 161,595
4235	Specific Service Charges	$ 175,242	$ 183,536
4245	Deferred Revenue - Contributed Capital	$ 84,800	$ -
4305	Regulatory Debits	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -
4355	Gain on Disposition of Other Property	$ -	$ (11,805)
4360	Loss on Disposition of Utility and Other Property	$ 68,267	$ 23,485
4375	Revenues from Non-Utility Operations	$ 1,346,416	$ 1,180,586
4380	Expenses of Non-Utility Operations	$ (1,230,597)	$ (1,265,806)
4390	Miscellaneous Non-Operating Income	$ 161,425	$ 128,123
4398	Foreign Exchange Gains & Losses	$ -	$ 735
4405	Interest & Dividend Income	$ 214,655	$ 152,714
Specific Service Charges		$ 175,242	$ 183,536
Late Payment Charges		$ 162,939	$ 161,595
Deferred Revenue Earned on Contributed Capital-REVERSED		$ 84,800	$ -
Other Operating Revenues		$ 591,904	$ 733,894
Other Income or Deductions		$ 560,168	$ 208,030
Total		$ 1,575,053	$ 1,287,055

Description

Specific Service Charges:
Late Payment Charges:
Other Distribution Revenues:
Other Income and Expenses:

Note: Add all applicable accounts listed above to the table and include all relevant information
The above table assumes adoption of MIFRS as of January 1, 2013. If the adoption year differs, please adjust the table accordingly.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4082 - Retailer Services Revenues

	Aug-12	Aug-13
Reporting Basis	CGAAP	CGAAP
Retailer Services Revenues	$ 42,622	$ 33,926

Total	$ 42,622	$ 33,926

Account 4084 - STR Revenue

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
STR Revenue	$ 1,501	$ 986
Total	$ 1,501	$ 986

Account 4086 - SSS Administration Charges

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
SSS Administration Charges	$ 164,228	$ 168,915
Total	$ 164,228	$ 168,915

Account 4210 - Rent from Electric Property

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Pole Rentals	$ 311,326	$ 503,855
Rent Revenue	$ 53,827	$ 7,213
Mobile Substation Revenue		
Total	$ 365,154	$ 511,068

Account 4220 - Other Electric Revenues

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Engineering Services	$ -	$ -
Control Room Services	$ 18,400	$ 19,000
Accounting Services	$ -	$ -
Total	$ 18,400	$ 19,000

Account 4225 - Late Payment Charges

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Late Payment Charges	$ 162,939	$ 161,595
Total	$ 162,939	$ 161,595

Account 4245 - Deferred Income - Contributed Capital

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Deferred Income - Contributed Capital	$ 84,800	$ -
Total	$ 84,800	$ -

Account 4235 - Specific Service Charges

	Aug-12	Aug-13

Reporting Basis	CGAAP	CGAAP
Unsealing Meters Revenue	$ 6,195	$ 8,490
Reconnection Charges Revenue	$ 29,283	$ 36,185
Change of Occupancy Charges	$ 104,030	$ 95,870
Returned Cheque Charges Revenue	$ 12,950	$ 13,040
Collection of Account Revenue - No Disconnection	$ 15,645	$ 18,840
Meter Dispute Revenue (if meter found correct)	$ -	$ 30
Unauthroized Meter Removal Revenue	$ 60	$ 780
Credit/Reference Check (plus credit agency costs)	$ -	$ -
MicroFIT Generators Service Charges	$ 7,080	$ 10,301
Total	$ 175,242	$ 183,536

Account 4305 - Regulatory Debits

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Accounting Charges Under CGAAP	$ -	$ -
Total	$ -	$ -

Account 4355 - Gain on Disposition of Other Property

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Proceeds on Disposition of Other Property	$ 71,221	$ 15,451
NBV of Assets Disposed	$ (2,954)	$ (3,771)
Total	$ 68,267	$ 11,680

Account 4360 - Loss on Utility & Other Plant

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Cost on Disposition of Utility Property	$ -	$ -
NBV of Assets Disposed	$ -	$ -
Total	$ -	$ -

Account 4375 - Revenue from Non-Utility Operations

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
OPA Programs	$ 480,170	$ 691,078
Streetlighting Services Revenues	$ 866,246	$ 489,508
Total	$ 1,346,416	$ 1,180,586

Account 4380 - Expenses from Non-Utility Operations

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
OPA Programs	$ (364,351)	$ (776,299)
Streetlighting Services Revenues	$ (866,246)	$ (489,508)
Total	$ (1,230,597)	$ (1,265,806)

Account 4390 - Miscellaneous Non-Operating Income

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**

Scrap Sales	$ 130,388	$ 101,370
Other Miscellaneous Non-Operating Revenue	$ 7,070	$ 2,243
A/P Discounts Taken/Lost	$ 23,967	$ 24,510
Foreign Exchange Gain/Loss	$ -	
Lease Option Consideration	$ -	
Total	$ 161,425	$ 128,123

Account 4398 - Foreign Exchange Gains & Losses

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Foreign Exchange Gains & Losses on USD Bank Account	$ -	$ 735
Total	$ -	$ 735

Notes:

Account 4405 - Interest and Dividend Income

	Aug-12	Aug-13
Reporting Basis	**CGAAP**	**CGAAP**
Short-term Investment Interest	$ 104,892	$ 16,027
Bank Deposit Interest	$ 109,764	$ 136,543
Prudential Interest Earned		
Interest Revenue on Variance Accounts		
Interest Revenue - PILS returns		
Miscellaneous Interest Revenue		$ 144
Total	$ 214,655	$ 152,714

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2014)

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B29 to E29. These results are taken from the final 2011 CDM Report issued by the OPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C30 to E30. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013. Until that report is issued, the distributor should use the results from the preliminary 2012 CDM Report issued in the spring of 2013.

Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

		4 Year (2011-2014) kWh Target:			
		98,411,344			
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	13.09%	12.98%	12.97%	12.79%	51.84%
2012 CDM Programs		6.67%	6.67%	6.67%	20.00%
2013 CDM Programs			9.39%	9.39%	18.77%
2014 CDM Programs				9.39%	9.39%
Total in Year	**13.09%**	**19.65%**	**29.03%**	**38.23%**	**100.00%**
		kWh			
2011 CDM Programs	12,882,628.59	12,777,283.21	12,766,732.78	12,588,174.12	51,014,818.70
2012 CDM Programs		6,561,443.00	6,561,443.00	6,561,443.00	19,684,329.00
2013 CDM Programs			9,237,398.77	9,237,398.77	18,474,797.54
2014 CDM Programs				9,237,398.77	9,237,398.77
Total in Year	**12,882,628.59**	**19,338,726.21**	**28,565,574.55**	**37,624,414.65**	**98,411,344.00**

From each of the 2006-2010 CDM Final Report, 2011 CDM Final Report, and the 2012 CDM Final Report, issued by the OPA for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D31 to E33. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis.

	Net-to-Gross Conversion			
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2014	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs	**178150499.9**	**135692930**		
2011 CDM program	**52431811.11**	**37374960.88**		
2012 CDM program	**50947313.91**	**36539763.6**		
2006 to 2011 OPA CDM programs: Persistence to 2014	281529624.9	209607654.5	71921970.44	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but also reflect the assumption that impacts of 2011 and 2012 programs are already implicitly reflected in the actual data for those years that are the basis for the load forecast prior to any manual CDM adjustment.

	Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast				
	2011	**2012**	**2013**	**2014**	
Weight Factor for each year's CDM program impact on 2014 load forecast	**1**	**1**	**1**	**1**	Utility can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Persistence of 2011 CDM programs for the full year of 2012 means that all of 2011 CDM impact is assumed to be in the base forecast before the CDM Adjustment*	*50% of 2012 CDM impact is assumed reflected in base forecast based on 1/2 year rule.*	*Full year impact of 2013 CDM programs on adjustment for 2014 load forecast*	*Only 50% of 2014 CDM impact is used based on a half year rule*	

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2014 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data, and is intended to reflect the further CDM savings that the distributor needs to achieve assuming that they meet 100% of the 2011-2014 CDM target that is a condition of their target.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner, for both the LRAMVA and for the load forecast adjustment.

	2011	**2012**	**2013** **kWh**	**2014**	**Total for 2014**
Amount used for CDM threshold for LRAMVA (2014)	12,588,174.12	6,561,443.00	9,237,398.77	9,237,398.77	37,624,414.65
Manual Adjustment for 2014 Load Forecast (billed basis)	12,588,174.12	6,561,443.00	9,237,398.77	9,237,398.77	37,624,414.65
Proposed Loss Factor (TLF)	1.04%	Format: X.XX%			
Manual Adjustment for 2014 Load Forecast (system purchased basis)	12,718,479.60	6,629,363.26	9,333,018.97	9,333,018.97	38,013,880.79

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.

Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Opening Balance	$ 13,881,503	$ 12,270,957	$ 13,724,479	$ 16,443,729	$ 17,431,075
Pension and Payroll Benefits		$ 29,260	$ 108,143	$ 108,013	$ 72,373
General Salary Increases		$ 212,237	$ 202,021	$ 206,745	$ 223,623
Human Resources - new Resource			$ 67,759	$ 51,040	$ 4,300
LEAP	-$ 47,476	$ 47,475			
Diversion of Resources to OPA Programs	-$ 38,898	-$ 25,020	-$ 46,393	-$ 91,816	-$ 9,875
HST Impact	-$ 11,504	-$ 39,810	-$ 69,902	-$ 40,000	
Diversion and reallocation of resources to complete TS9	-$ 779,303	$ 753,893			
Increase in Non recoverable Pole accidents		$ 99,677	-$ 32,428		
Network Protector and Transformer Maintenance		$ 128,037			
Additional Admin Credit	-$ 257,997			$ 101,425	-$ 15,000
Collection of a bad debt previously deemed uncollectible	-$ 266,362	$ 146,300			
Reduction in AR Credit insurance - End of program	-$ 106,950	-$ 58,049			
Retirements and Resignations - Finance	-$ 102,056				
Wood Pole Survey				$ 50,000	
Overhead Line Maintenance				$ 109,434	
Remove Dead Ash Trees				$ 50,000	$ 50,000
Liability Insurance Rebate Received in 2012, not in 2013				$ 95,978	$ 6,900
IT programs				$ 266,724	$ 267,700
Increased Staffing Resources and Overtime				$ 168,000	$ 120,400
IFRS Changes			$ 1,227,168	$ 210,320	$ 4,206
Monthly Billing - Customer Service - Billing				$ 168,000	$ 164,000
Monthly Billing - Customer Service - Collecting				$ 33,500	$ 36,000
Effect of the Smart Meter Decision			$ 1,084,463	-$ 739,463	
Increased Labour due to Smart Meters				$ 162,986	
Increased OMA as a result of Smart Meters					$ 6,900
Other Programs		$ 122,579	$ 128,281	$ 33,393	$ 104,590
Inflation		$ 36,943	$ 50,138	$ 43,067	$ 56,009
Closing Balance	$ 12,270,957	$ 13,724,479	$ 16,443,729	$ 17,431,075	$ 18,523,201

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

4 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	32	31	30	33	33	34
Non-Management (union and non-union)	142	141	142	141	142	143
Total	174	172	172	174	175	177
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	$ 3,109,607	$ 3,097,650	$ 2,993,370	$ 3,264,405	$ 3,464,895	$ 3,610,775
Non-Management (union and non-union)	$ 9,972,315	$ 9,328,967	$ 10,445,295	$ 10,249,487	$ 10,406,274	$ 10,706,801
Total	$ 13,081,922	$ 12,426,617	$ 13,438,665	$ 13,513,892	$ 13,871,169	$ 14,317,576
Total Benefits (Current + Accrued)						
Management (including executive)	$ 182,969	$ 596,015	$ 678,756	$ 776,291	$ 878,231	$ 920,332
Non-Management (union and non-union)	$ 760,329	$ 2,273,155	$ 2,416,645	$ 2,554,971	$ 2,781,052	$ 2,940,916
Total	$ 943,298	$ 2,869,170	$ 3,095,401	$ 3,331,262	$ 3,659,283	$ 3,861,248
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 3,292,576	$ 3,693,665	$ 3,672,126	$ 4,040,696	$ 4,343,126	$ 4,531,107
Non-Management (union and non-union)	$ 10,732,644	$ 11,602,122	$ 12,861,940	$ 12,804,458	$ 13,187,326	$ 13,647,717
Total	$ 14,025,220	$ 15,295,787	$ 16,534,066	$ 16,845,154	$ 17,530,452	$ 18,178,824

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

Appendix 2-TB
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years,
Sub-account HST/OVAT Input Tax Credits (ITCs)

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries.

100% of the balance in Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs), should be recorded in this table.

Summary of PST Savings from 2009 Historic Year Analysis

	Principal 2010	Principal 2011	Principal 2012	Principal 2013	Principal Jan-April 2014 [1]	Carrying Charges to April 30, 2014	Total Account 1592, sub-account HST/OVAT Balance
OM&A Expenses PST Savings	$ 45,271	$ 100,086	$ 139,501	$ -	$ -	$ 39,547	$ 324,404
Capital Items PST Savings							$ -
Total Annual PST Savings [2]	$ 45,271	$ 100,086	$ 139,501	$ -	$ -	$ 39,547	$ 324,404

[1] Include January to April 30, 2014 PST savings if the rate year begins May 1, 2014. If the rate year begins Jan 1, 2014, include PST savings to December 31, 2013.
[2] Derived PST savings proxy for each year per 2009 historic year analysis

Note: Assumes level OM&A and Capital Spending year over year. An alternative detailed transactional analysis may also be performed using actual expenditures from 2010 to the start of the rate year.

Print Form

Low-Income Energy Assistance Program
(LEAP)
Funds Disbursement Report
Electricity

(For use by social service agencies only)

On February 4, 2011, the Ontario Energy Board (the "Board") issued a letter describing the information to be filed by electricity and natural gas distributors in relation to the provision of emergency financial assistance under the Low-Income Energy Assistance Program ("LEAP").

On December 21, 2011, the Board issued a subsequent letter, stating that to facilitate the filing process, and for consistency in reporting, it would provide an editable PDF input form for use by social agency partners, that distributors can then use in turn to populate the electronic input form for filing with the Board.

To that end, this editable PDF form outlines the information to be provided by electricity distributor's social agency partner(s) in relation to LEAP emergency financial assistance.

LEAP funds received from:		
Distributor (a)	Non-distributor sources * (b)	Total funds received (a+b)
$47,475.00	$7,848.00	$55,323.00

* Funds received by the distributor from a third party or from the distributor's shareholder(s) (i.e., not funded from distribution revenues) as a donation and then provided by the distributor to its social agency partner(s).

Note: Funds received under the terms of the settlement of the class action proceeding regarding late payment penalties should not be included in any of the above.

LEAP funds disbursed for:				
Agency administration and program delivery (a)	Grants to distributor customers (b)	Grants to unit sub-metered customers** (c)	Total grants disbursed (b+c)	Total funds disbursed (a+b+c)
$7,121.00	$48,095.00		$48,095.00	$55,216.00

** Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

Month in which LEAP funds were depleted:	July - $107 balance

Number of LEAP applicants who were:		
Distributor customers (a)	Unit sub-metered customers** (b)	Total (a+b)
137		137

** Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

Number of applicants assisted who were:		
Distributor customers (a)	Unit sub-metered customers** (b)	Total assisted (a+b)
137		137

** Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

Number of applicants denied who were:		
Distributor customers (a)	Unit sub-metered customers** (b)	Total denied (a+b)
2		2

** Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

Average grant per accepted applicant for:		
Distributor customers	Unit sub-metered customers**	Overall average
$351.06		$351.06

** Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

Note: Average amount calculations are as follows:

- Distributor Customers = Grants to distributor customers/assisted distributor customers
- Unit sub-metered customers = Grants to unit sub-metered customers/assisted unit sub-metered customers
- Average across all customers = Total grants disbursed/total applicants assisted

Comments:	**We strive to assist all applicants in one way or another. For households that don't qualify as per LEAP criteria, we look to other sources of funding.** **In addition to LEAP funds, $7,848 was provided to Kitchener-Wilmot Hydro customers through Provincial Emergency Energy Fund (EEF). Households may also be assisted via OW discretionary benefits.**

Low-Income Energy Assistance Program (LEAP)
Emergency Financial Assistance
Monthly Monitoring Report

Print Form

As per Appendix C.3 of the LEAP Emergency Financial Assistance Program Manual, the following is a list of information that intake and/or lead agencies should track on a monthly basis. This information should be collected by the agencies throughout the year, to be submitted to their respective utility partner(s) by February 28 of the following year. This information will be used to evaluate program performance.

Distributor: Kitchener-Wilmot Hydro Inc.

Distributor Contact

Name: Rhonda Yaraskavitch **Email:** ryaraskavitch@kwhydro.on.ca **Phone:** 519-745-4774 x 281

Lead Agency: Region of Waterloo Social Services

Lead Agency Contact

Name: Van Vilaysinh **Email:** vvilaysinh@regionofwaterloo.ca **Phone:** 519-575-4757 x 5824

Comments: **Prior to LEAP, funds for the Waterloo Region Energy Assistance Program (WREAP) was provided voluntarily through local utility partners. This allowed for flexible eligibility guidelines, where funds were pooled together so that assistance was provided across Waterloo Region according to need. While the amount of funds has increased as a result of the LEAP mandate, the flexibility in eligibility criteria has decreased, creating challenges in the coordination, distribution and reporting of the funds.**

	Total number of adults assisted (a)	Total number of children assisted (b)	Total number of applications received (c)	Total monthly income of all applicants (d)	Average monthly income per application (d/c)
January	24	31	17	31543	1855
February	27	23	17	27874	1640
March	44	49	29	17715	611
April	34	26	24	16492	687
May	18	20	14	10061	719
June	27	28	20	16461	823
July	18	20	11	11496	1045
August					
September					
October					
November					
December					
Total	192	197	132	131641	997

Number of Applicants by Primary Source of Household Income*

	Employment Income	Ontario Works (OW)	Child Tax Benefit (CTB)	Ontario Disability Support Program (ODSP)	Workplace Safety and Insurance Board (WSIB)	Social Assistance	Employment Insurance (EI)	Ontario Student Assistance Program (OSAP)	Canada Pension Plan (CPP)	Other (Please specify in comments box below)
January	9	1		3	1		3			
February	8	1		4	1		3			
March	14	5	1	2			6	1		
April	8	4		4			7	1		
May	6	4		1				3		
June	6	7		3	1		1	1		1
July	5	3						2	1	
August										
September										
October										
November										
December										
Total	56	25	1	17	3		20	8		

Comments: **Other = ex spouse pays mortgage, income from boarder**

* More than one primary source of income may be selected per applicant

Number of Applicants by Housing Type

	Rent	Own	Community or Social Housing	Other	Total
January	8	6	3		
February	14	3			17
March	18	7	4		29
April	21	2	1		24
May	9	3	2		14
June	17	3			20
July	6	3	2		11
August					
September					
October					
November					
December					
Total	93	27	12		132

Comments:	**January Total = 17**

Number of Applicants by Marital Status*

	Single (No Children)	Single (With Children)	Married or Common-Law (No Children)	Married or Common-Law (With Children)	Other (Please specify in comments box below)	Total
January	5	5	1	6		17
February	4	4	2	7		17
March	2	12	4	11		29
April	9	5	2	8		24
May	5	5	1	3		14
June	4	9	1	6		20
July	2	2		7		11
August						
September						
October						
November						
December						
Total	93	27	12			132

Comments:

* To be provided, if data is available

Number of Applicants Not Accepted by Reason

	Did Not Meet Eligibility Criteria	Already Accessed Funds During Program Year	Insufficient Funds Remaining	Other (Please specify in comments box below)
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total				

Comments:	The Waterloo Region Energy Assistance Program includes funding from various sources. When a person calls for assistance, we do not consider them to be applying directly for Kitchener-Wilmot Hydro funds. They are assessed for the funding that they are eligible for. As such, all applicants are assisted. For example, although funds were depleted in July, we continue to assist Kitchener-Wilmot Hydro customers year round.

Month	Number of Applications where Grant Amount was Adequate to Cover Arrears	Number of Applicants Referred to Utility Conservation Programs	Number of Applications where Funding was not Required because Advocacy with Utility was Successful
January	15	1	
February	15		
March	26	2	
April	14	1	
May	14		
June	13		
July	9		
August			
September			
October			
November			
December			
Total	106	4	

Comments:

	Total Amount of Arrears for All Applicants (a)	Number of Applicants (b)	Average Arrears Owed per Applicant (a/b)
January	5090	17	299
February	4565	17	269
March	8907	29	307
April	10492	24	437
May	3409	14	244
June	12395	20	620
July	3974	11	361
August			
September			
October			
November			
December			
Total	48833	132	370

Number of Applicants Requesting Assistance by Reason*

	Job Loss	Illness	Unusually High Bill	Pending EI	Other (Please specify in comments box below)
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					
Total					

Comments: Everyone who accessed the energy assistance program did so to avoid disconnection. Their particular circumstances that led them to seek assistance is not well documented. Oftentimes issues with energy arrears occurs over a longer period, where people are continually struggling to pay rent, food, etc. and are unable to pay for utility from time to time. While unforeseen circumstances (e.g. job loss, illness) may be "triggers" to accessing assistance they are not necessarily the

* More than one reason may be selected per applicant

	Number of Applicants by Information Source*											
	Word of Mouth	**Utility Referral**	**Utility Website**	**Social Agency**	**Ontario Energy Board website**	**Ontario Energy Board Customer Relations Centre**	**Television**	**Radio**	**Newspaper**	**Billing Insert**	**Poster**	**Other** (Please specify in comments box below)
January		7		3								7
February		7		8								2
March	1	13		12								3
April		12		11								1
May		6		6								2
June		11		8								1
July		6		3								2
August												
September												
October												
November												
December												
Total	1	62		51								18

Comments: **Other = applied for assistance in previous year(s)**

* More than one information source may be selected per applicant

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2012 Results Report. We have seen a 39% increase in energy savings for our new province-wide 2011-2014 suite of saveONenergy initiatives. Overall progress to targets is moving up with 29% of demand and 65% of energy savings achieved. Many LDCs, both large and small, continue to stay on track to meet or exceed their OEB targets. Conservation programs continue to be a valuable and cost effective resource for customers across the province, over the past two years the program cost to consumers remains within 3 cents per kWh.

Further to programmatic savings, capability building efforts launched in 2011 are yielding healthy enabled savings through Embedded Energy Managers and Audit initiative projects. The strong momentum continues in 2013.

We remain committed to ensuring LDCs are successful in meeting their objectives and our collective efforts to date have improved the current program suite by offering more local program opportunities, implementing a new expedited change management process, and enhancing incentives to make it easier for customers to participate in programs. We invite you to continue to provide your feedback to us and to celebrate our successes as we move forward.

The format of this report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. All results are now considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year.

Sincerely,

Andrew Pride

Table of Contents		

OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

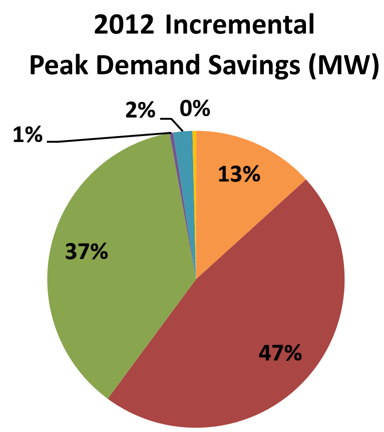
LDC: Kitchener-Wilmot Hydro Inc.

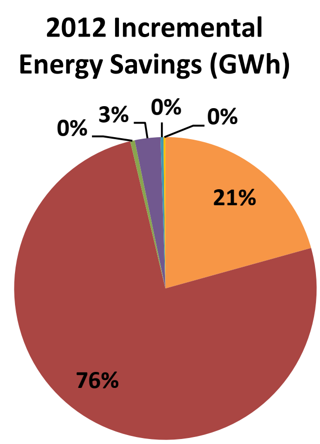
FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	3.4	4.0	**18.6%**	**27.2%**
Net Energy Savings (GWh)	6.6	70.9	**78.6%**	**78.7%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector

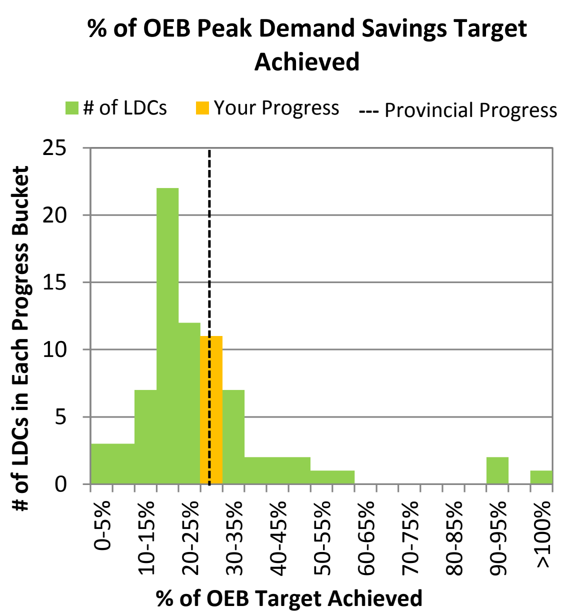




Consumer Business Industrial HAP Pre-2011 True-up

Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)



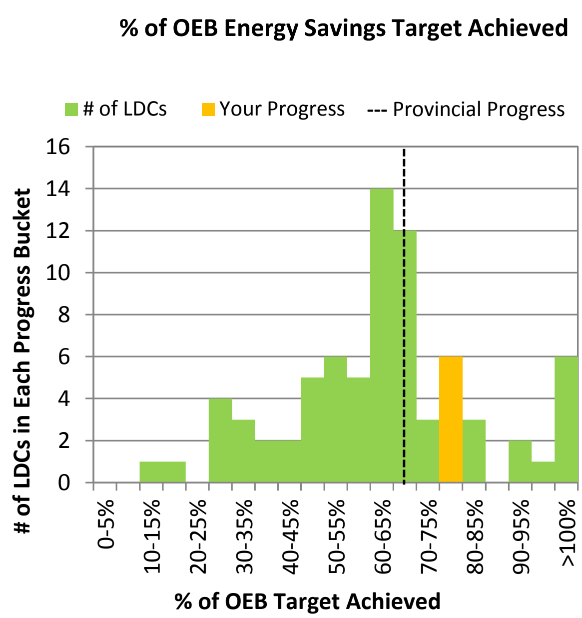


Table 1: **Kitchener-Wilmot Hydro Inc.** Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	631	335			36	20			262,506	134,960			55	1,453,993
Appliance Exchange	Appliances	69	54			7	8			8,561	14,106			11	72,637
HVAC Incentives	Equipment	2,261	1,767			642	401			1,178,372	689,786			1,043	6,782,846
Conservation Instant Coupon Booklet	Items	8,184	504			19	4			305,679	22,805			23	1,291,132
Bi-Annual Retailer Event	Items	14,195	17,303			27	24			479,313	436,812			52	3,227,688
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	271	0			152	0			0	0			0	0
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**883**	**457**			**2,234,431**	**1,298,468**			**1,182**	**12,828,296**
Business Program															
Retrofit	Projects	50	95			564	812			3,057,370	3,955,522			1,326	23,877,781
Direct Install Lighting	Projects	239	193			261	170			631,336	624,605			380	4,241,412
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	1			0	30			0	51,506			30	154,519
Energy Audit	Audits	0	4			0	21			0	100,705			21	302,115
Small Commercial Demand Response	Devices	9	0			6	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	7	8			455	580			17,768	8,426			0	26,193
Business Program Total						**1,285**	**1,612**			**3,706,474**	**4,740,764**			**1,757**	**28,602,020**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	10				40				271,185				40	1,084,740
Demand Response 3	Facilities	4	3			1,453	1,275			85,285	30,717			0	116,002
Industrial Program Total						**1,493**	**1,275**			**356,470**	**30,717**			**40**	**1,200,742**
Home Assistance Program															
Home Assistance Program	Homes	0	171			0	14			0	171,520			14	514,561
Home Assistance Program Total						**0**	**14**			**0**	**171,520**			**14**	**514,561**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	68	0			964	0			6,580,023	0			964	26,320,092
High Performance New Construction	Projects	0	2			1	71			5,230	19,804			72	80,334
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**965**	**71**			**6,585,253**	**19,804**			**1,037**	**26,400,426**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-13**				**352,831**			**-16**	**1,403,138**
Energy Efficiency Total						**2,561**	**1,574**			**12,779,576**	**6,222,132**			**4,029**	**69,403,850**
Demand Response Total (Scenario 1)						**2,066**	**1,854**			**103,052**	**39,143**			**0**	**142,195**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**4,626**	**3,416**			**12,882,629**	**6,614,105**			**4,013**	**70,949,183**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
Full OEB Target:	**21,560**	**90,290,000**
% of Full OEB Target Achieved to Date (Scenario 1):	**18.6%**	**78.6%**

Table 2: Adjustments to **Kitchener-Wilmot Hydro Inc.** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-391				-108				-193,765				-108	-775,061
Conservation Instant Coupon Booklet	Items	134				0				4,496				0	17,984
Bi-Annual Retailer Event	Items	1,334				2				35,611				2	142,445
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-106**				**-153,658**				**-106**	**-614,632**
Business Program															
Retrofit	Projects	6				44				290,598				44	1,162,394
Direct Install Lighting	Projects	7				7				16,168				3	56,486
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	2				10				50,353				10	201,410
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**61**				**357,119**				**57**	**1,420,290**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	3				23				141,576				0	566,303
High Performance New Construction	Projects	1				9				7,794				9	31,176
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**32**				**149,370**				**9**	**597,480**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-13**				**352,831**				**-16**	**1,403,138**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3: Kitchener-Wilmot Hydro Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		0.95				0.76				1.06				0.76		
Direct Install Lighting		0.68				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		1.00				0.49				1.00				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		1.09				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	4.6	2.6	2.6	2.5
2012 - Verified		3.4	1.5	1.5
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				**4.0**
Kitchener-Wilmot Hydro Inc. 2014 Annual CDM Capacity Target				**21.6**
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				**18.6%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	12.9	12.8	12.8	12.6	51.0
2012 - Verified		6.6	6.5	6.4	19.9
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**70.9**
Kitchener-Wilmot Hydro Inc. 2011-2014 Annual CDM Energy Target					**90.3**
Verified Portion of Cumulative Energy Target Achieved (%):					**78.6%**

*2011 energy adjustments included in cumulative energy savings.

Table 6: Province-Wide Initiatives and Program Level Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Items	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Items	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	98,388			10,947	49,038			24,870	359,408			0	384,279
Residential Demand Response (IHD)	Devices	0	49,689			0				0					
Residential New Construction	Homes	7	19			0	2			743	17,152			2	54,430
Consumer Program Total						**49,681**	**72,377**			**133,520,941**	**75,796,859**			**61,696**	**760,348,879**
Business Program															
Retrofit	Projects	2,516	5,605			24,467	61,147			136,002,258	314,922,468			84,018	1,480,647,459
Direct Install Lighting	Projects	20,297	18,494			23,724	15,284			61,076,701	57,345,798			31,181	391,072,869
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	69			123	764			411,717	1,814,721			888	7,091,031
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response	Devices	132	294			84	187			157	1,068			0	1,224
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3*	Facilities	145	151			16,218	19,389			633,421	281,823			0	915,244
Business Program Total						**64,617**	**98,221**			**198,124,253**	**381,415,230**			**117,535**	**1,900,875,881**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	39			0	1,086			0	7,372,108			1,086	22,116,324
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	74,056			3,080,737	1,784,712			0	4,865,449
Industrial Program Total						**57,098**	**75,141**			**31,947,577**	**9,156,820**			**5,699**	**142,444,054**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033			2	566			39,283	5,442,232			569	16,483,831
Home Assistance Program Total						**2**	**566**			**39,283**	**5,442,232**			**569**	**16,483,831**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	69			5,098	3,251			26,185,591	11,901,944			8,349	140,448,197
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**			**243,251,550**	**11,901,944**			**48,195**	**1,008,712,030**
Other															
Program Enabled Savings	Projects	0	16			0	2,304			0	1,188,362			2,304	3,565,086
Time-of-Use Savings	Homes														
Other Total							**2,304**				**1,188,362**			**2,304**	**3,565,086**
Adjustments to Previous Year's Verified Results							**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total						**136,610**	**109,191**			**603,144,419**	**482,474,435**			**235,998**	**3,826,263,564**
Demand Response Total (Scenario 1)						**79,733**	**142,670**			**3,739,185**	**2,427,011**			**0**	**6,166,196**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**			**606,883,604**	**503,590,526**			**237,154**	**3,906,348,358**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**17.8%**	**65.1%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 7: Adjustments to **Province-Wide** Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-18,866				-5,278				-9,721,817				-5,278	-38,887,267
Conservation Instant Coupon Booklet	Items	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Items	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	19				1				13,767				1	55,069
Consumer Program Total						**-5,153**				**-7,249,004**				**-5,153**	**-28,996,015**
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	12				828				3,520,620				828	14,082,482
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**5,014**				**23,328,565**				**4,764**	**92,471,668**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12				138				545,536				138	2,182,145
High Performance New Construction	Projects	34				1,407				2,065,200				1,407	8,260,800
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**1,545**				**2,610,736**				**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**1,406**				**18,690,297**				**1,156**	**73,918,598**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.65				0.49				7.17				0.49		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		0.98				0.49				0.99				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.16				0.90				1.16				0.90		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.32				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		1.06				1.00				2.26				1.00		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		253.3	109.8	108.2
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				**237.2**
2014 Annual CDM Capacity Target				**1,330**
Verified Peak Demand Savings Target Achieved - 2011 (%):				**17.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		503.6	498.4	492.6	1,513
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**3,906**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Energy Target Achieved - 2011 (%):					**65.1%**

*2011 energy adjustments included in cumulative energy savings.

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings =** Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings =** Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2012 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		

<table>
<tr><th>Initiative</th><th>Attributing Savings to LDCs</th><th>Savings 'start' Date</th><th>Calculating Resource Savings</th></tr>
<tr><td>Direct Installed Lighting</td><td>Results are directly attributed to LDC based on the LDC specified on the work order</td><td>Savings are considered to begin in the year of the actual project completion date.</td><td>Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).</td></tr>
<tr><td>Existing Building Commissioning Incentive</td><td>Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.</td><td>Savings are considered to begin in the year of the actual project completion date.</td><td rowspan="2">Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
<tr><td>New Construction and Major Renovation Incentive</td><td>Results are directly attributed to LDC based on LDC identified in the application.</td><td>Savings are considered to begin in the year of the actual project completion date.</td></tr>
<tr><td>Energy Audit</td><td>Projects are directly attributed to LDC based on LDC identified in the application</td><td>Savings are considered to begin in the year of the audit date.</td><td>Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
</table>

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; No completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

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UTILITY	JOURNEYMAN LINEPERSON	JOURNEYMAN METERPERSON	SENIOR ENG TECHNOLOGIST/ TECHNICIAN	SENIOR PLANNER	SENIOR CUSTOMER SERVICE REP	ACCOUNTING CLERK	OPERATIONS CLERK	STOREKEEPER	RATE INCREASE
BURLINGTON HYDRO INC.	effective April 1 2012 = $37.83 2013 = $38.92	effective April 1 2012 = $37.83 2013 = $38.92	$39.99	n/a	effective April 1 2012 = $32.34 2013 = $33.28	*Accounting Clerk I* effective April 1 2012 = $28.12 2013 = $28.94	*Engineering Clerk* effective April 1 2012 = $31.24 2013 = $32.15	effective April 1 SR. 2012 = $34.03 2013 = $35.02 JR. 2012 = $30.80 2013 = $31.69	IBEW 2012 = 2.9% 2013 = 2.9%
CAMBRIDGE & NORTH DUMFRIES HYDRO INC.	2013 - 39.12 2012 - 37.98 2011 - 36.87 2010 - $35.80	2013 - 35.12 2012 - 34.10 2011 - 34.91 2010 - $33.89		n/a	2013 - 33.52 2012 - 32.54 2011 - 31.59 2010 - 30.67	2013 - 27.30 2012 - 26.50 2011 - 25.73 2010 - 24.98	2013 - 28.00 2012 - 27.18 2011 - 26.39 2010 - $25.62	2013 - 30.83 2012 - 29.93 2011 - 29.06 2010 - $28.21	3% 3% 3% 3%
GUELPH HYDRO ELECTRIC SYSTEMS	2012 = $36.58	2012 = $35.23		n/a	n/a	2012 = $27.10	2012 = $29,83 Upgraded to Administrative Assistant Operations	Stores - 2012 = $27.10 Stockkeeper - 2012 = $29.83	2010 - 3% 2011 - 3% 2012 - 3%
KITCHENER-WILMOT HYDRO	2012 - $36.43 2013 - $37.45 2014 - $38.52	2012 - $36.43 2013 - $37.45 2014 - $38.52	Technician 2012 = $28.50 Technologist = $36.11	n/a	(Cust. Serv. Clerk) $24.17	2012- $27.72 2013- $28.50 2014- $29.31	2012 - $25.82 2013 - $26.54 2014 - $27.30	(Stockkeeper) 2012 - $25.82 2013 - $26.54 2014 - $27.30	2012 - 2.75% 2013 - 2.80% 2014 - 2.85% (Salaried IBEW - same)
LONDON HYDRO	2012=36.42	2012=36.42	2012 = $36.42	n/a	2012=29.71	2012=27.54	2012=26.44	2012-26.44	2012=3%
MILTON HYDRO DISTRIBUTION INC.	Jan 1 2012 =$36.52 Apr 1 2012=$36.87	Jan 1 2012 =$37.11 Apr 1 2012=$37.21		N/A	Jan 1 2012 =$27.55 Apr 1 2012=$27.62	Jan 1 2012 =$27.55 Apr 1 2012=$27.62	Jan 1 2012 =$27.55 Apr 1 2012=$27.62	Jan 1 2012 =$24.14 Apr 1 2012=$24.20	Jan 1 2012 = 2.75% Apr 1 2012= 0.25% (plus $0.25 special adjustment for linemen)
WATERLOO NORTH HYDRO INC	April 1, 2010 = $34.32 April 1, 2011 = $35.35 April 1, 2012 = $36.41	April 1, 2010 = $34.32 April 1, 2011 = $35.35 April 1, 2012 = $36.41	$36.41	(Eng Tech III) April 1, 2010 = $34.32 April 1, 2011 = $35.35 April 1, 2012 = $36.41	April 1, 2010 = $27.11 April 1, 2011 = $27.92 April 1, 2012 = $28.76	April 1, 2010 = $25.44 April 1, 2011 = $26.20 April 1, 2012 = $26.99	April 1, 2010 = $25.44 April 1, 2011 = $26.20 April 1, 2012 = $26.99	April 1, 2010 = $25.44 April 1, 2011 = $26.20 April 1, 2012 = $26.99	Wage Increase 2010, 2011,2012: 2010 - 3.0% 2011 - 3.0% 2012 - 3.0%

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RTSR Workform for Electricity Distributors (2014 Filers)

Utility Name	Kitchener-Wilmot Hydro Inc.
Service Territory	
Assigned EB Number	EB-2013-0147
Name and Title	Margaret Nanninga, V-P Finance
Phone Number	519-749-6177
Email Address	mnanninga@kwhydro.ca
Date	23-Sep-13
Last COS Re-based Year	**2010**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

RTSR Workform for Electricity Distributors (2014 Filers)

RTSR Workform for Electricity Distributors (2014 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	$ 0.0067	$ 0.0014
General Service Less Than 50 kW	kWh	$ 0.0058	$ 0.0013
General Service 50 to 4,999 kW	kW	$ 3.0721	$ 0.6740
Large Use	kW	$ 2.8874	$ 0.6335
Unmetered Scattered Load	kWh	$ 0.0058	$ 0.0013
Street Lighting	kW	$ 1.8681	$ 0.4101
Embedded Distributor	kW	$ 2.8965	$ 0.6356
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
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Choose Rate Class			
Choose Rate Class			

RTSR Workform for Electricity Distributors (2014 Filers)

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**	644,467,300		1.0320		665,090,254	-
General Service Less Than 50 kW	**kWh**	240,981,970		1.0320		248,693,393	-
General Service 50 to 4,999 kW	**kW**		2,227,931		**0.00%**	-	2,227,931
Large Use	**kW**		136,790		**0.00%**	-	136,790
Unmetered Scattered Load	**kWh**	3,696,460		1.0320		3,814,747	-
Street Lighting	**kW**		44,299		**0.00%**	-	44,299
Embedded Distributor	**kW**		37,867		**0.00%**	-	37,867

RTSR Workform for Electricity Distributors (2014 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.57	$ 3.63	$ 3.63
Line Connection Service Rate	kW	$ 0.80	$ 0.75	$ 0.75
Transformation Connection Service Rate	kW	$ 1.86	$ 1.85	$ 1.85

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 3.18	$ 3.18
Line Connection Service Rate	kW	$ 0.64	$ 0.70	$ 0.70
Transformation Connection Service Rate	kW	$ 1.50	$ 1.63	$ 1.63
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.33	$ 2.33

If needed , add extra host here (I)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed , add extra host here (II)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

Hydro One Sub-Transmission Rate Rider 9A	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ -	$ 0.1465	$ 0.1465
RSVA Transmission connection – 4716 – which affects 1586	kW	$ -	$ 0.0667	$ 0.0667
RSVA LV – 4750 – which affects 1550	kW	$ -	$ 0.0475	$ 0.0475
RARA 1 – 2252 – which affects 1590	kW	$ -	$ 0.0419	$ 0.0419
RARA 1 – 2252 – which affects 1590 (2008)	kW	$ -	-$ 0.0270	-$ 0.0270
RARA 1 – 2252 – which affects 1590 (2009)	kW	$ -	-$ 0.0006	-$ 0.0006
Hydro One Sub-Transmission Rate Rider 9A	kW	$ -	$ 0.2750	$ 0.2750

		Historical 2012	Current 2013	Forecast 2014
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data".
For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	306,063	$3.57	$ 1,092,645	314,528	$0.80	$ 251,622		$0.00		$ 251,622
February	271,586	$3.57	$ 969,562	287,720	$0.80	$ 230,176		$0.00		$ 230,176
March	284,333	$3.57	$ 1,015,069	289,988	$0.80	$ 231,990		$0.00		$ 231,990
April	252,213	$3.57	$ 900,400	259,765	$0.80	$ 207,812		$0.00		$ 207,812
May	329,290	$3.57	$ 1,175,565	330,963	$0.80	$ 264,770		$0.00		$ 264,770
June	360,467	$3.57	$ 1,286,871	372,023	$0.80	$ 297,618		$0.00		$ 297,618
July	380,602	$3.57	$ 1,358,749	388,981	$0.80	$ 311,185		$0.00		$ 311,185
August	335,929	$3.57	$ 1,199,267	342,698	$0.80	$ 274,158		$0.00		$ 274,158
September	302,255	$3.57	$ 1,079,050	313,205	$0.80	$ 250,564		$0.00		$ 250,564
October	272,862	$3.57	$ 974,117	282,646	$0.80	$ 226,117		$0.00		$ 226,117
November	297,213	$3.57	$ 1,061,050	311,090	$0.80	$ 248,872		$0.00		$ 248,872
December	286,509	$3.57	$ 1,022,837	301,126	$0.80	$ 240,901		$0.00		$ 240,901
Total	3,679,322	$ 3.57	$ 13,135,183	3,794,733	$ 0.80	$ 3,035,786	-	$ -	$ -	$ 3,035,786

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	306,063	$3.57	$ 1,092,645	314,528	$0.80	$ 251,622	-	$0.00	$ -	$ 251,622
February	271,586	$3.57	$ 969,562	287,720	$0.80	$ 230,176	-	$0.00	$ -	$ 230,176
March	284,333	$3.57	$ 1,015,069	289,988	$0.80	$ 231,990	-	$0.00	$ -	$ 231,990
April	252,213	$3.57	$ 900,400	259,765	$0.80	$ 207,812	-	$0.00	$ -	$ 207,812
May	329,290	$3.57	$ 1,175,565	330,963	$0.80	$ 264,770	-	$0.00	$ -	$ 264,770
June	360,467	$3.57	$ 1,286,871	372,023	$0.80	$ 297,618	-	$0.00	$ -	$ 297,618
July	380,602	$3.57	$ 1,358,749	388,981	$0.80	$ 311,185	-	$0.00	$ -	$ 311,185
August	335,929	$3.57	$ 1,199,267	342,698	$0.80	$ 274,158	-	$0.00	$ -	$ 274,158
September	302,255	$3.57	$ 1,079,050	313,205	$0.80	$ 250,564	-	$0.00	$ -	$ 250,564
October	272,862	$3.57	$ 974,117	282,646	$0.80	$ 226,117	-	$0.00	$ -	$ 226,117
November	297,213	$3.57	$ 1,061,050	311,090	$0.80	$ 248,872	-	$0.00	$ -	$ 248,872
December	286,509	$3.57	$ 1,022,837	301,126	$0.80	$ 240,901	-	$0.00	$ -	$ 240,901
Total	3,679,322	$ 3.57	$ 13,135,183	3,794,733	$ 0.80	$ 3,035,786	-	$ -	$ -	$ 3,035,786

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 3,035,786

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	306,063	$ 3.6300	$ 1,111,009	314,528	$ 0.7500	$ 235,896	-	$ 1.8500	$ -	$ 235,896
February	271,586	$ 3.6300	$ 985,857	287,720	$ 0.7500	$ 215,790	-	$ 1.8500	$ -	$ 215,790
March	284,333	$ 3.6300	$ 1,032,129	289,988	$ 0.7500	$ 217,491	-	$ 1.8500	$ -	$ 217,491
April	252,213	$ 3.6300	$ 915,533	259,765	$ 0.7500	$ 194,824	-	$ 1.8500	$ -	$ 194,824
May	329,290	$ 3.6300	$ 1,195,323	330,963	$ 0.7500	$ 248,222	-	$ 1.8500	$ -	$ 248,222
June	360,467	$ 3.6300	$ 1,308,495	372,023	$ 0.7500	$ 279,017	-	$ 1.8500	$ -	$ 279,017
July	380,602	$ 3.6300	$ 1,381,585	388,981	$ 0.7500	$ 291,736	-	$ 1.8500	$ -	$ 291,736
August	335,929	$ 3.6300	$ 1,219,422	342,698	$ 0.7500	$ 257,024	-	$ 1.8500	$ -	$ 257,024
September	302,255	$ 3.6300	$ 1,097,186	313,205	$ 0.7500	$ 234,904	-	$ 1.8500	$ -	$ 234,904
October	272,862	$ 3.6300	$ 990,489	282,646	$ 0.7500	$ 211,985	-	$ 1.8500	$ -	$ 211,985
November	297,213	$ 3.6300	$ 1,078,883	311,090	$ 0.7500	$ 233,318	-	$ 1.8500	$ -	$ 233,318
December	286,509	$ 3.6300	$ 1,040,028	301,126	$ 0.7500	$ 225,845	-	$ 1.8500	$ -	$ 225,845
Total	3,679,322	$ 3.63	$ 13,355,939	3,794,733	$ 0.75	$ 2,846,050	-	$ -	$ -	$ 2,846,050

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
February	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
March	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
April	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
May	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
June	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
July	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
August	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
September	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
October	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
November	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
December	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	306,063	$3.63	$ 1,111,009	314,528	$0.75	$ 235,896	-	$0.00	$ -	$ 235,896
February	271,586	$3.63	$ 985,857	287,720	$0.75	$ 215,790	-	$0.00	$ -	$ 215,790
March	284,333	$3.63	$ 1,032,129	289,988	$0.75	$ 217,491	-	$0.00	$ -	$ 217,491
April	252,213	$3.63	$ 915,533	259,765	$0.75	$ 194,824	-	$0.00	$ -	$ 194,824
May	329,290	$3.63	$ 1,195,323	330,963	$0.75	$ 248,222	-	$0.00	$ -	$ 248,222
June	360,467	$3.63	$ 1,308,495	372,023	$0.75	$ 279,017	-	$0.00	$ -	$ 279,017
July	380,602	$3.63	$ 1,381,585	388,981	$0.75	$ 291,736	-	$0.00	$ -	$ 291,736
August	335,929	$3.63	$ 1,219,422	342,698	$0.75	$ 257,024	-	$0.00	$ -	$ 257,024
September	302,255	$3.63	$ 1,097,186	313,205	$0.75	$ 234,904	-	$0.00	$ -	$ 234,904
October	272,862	$3.63	$ 990,489	282,646	$0.75	$ 211,985	-	$0.00	$ -	$ 211,985
November	297,213	$3.63	$ 1,078,883	311,090	$0.75	$ 233,318	-	$0.00	$ -	$ 233,318
December	286,509	$3.63	$ 1,040,028	301,126	$0.75	$ 225,845	-	$0.00	$ -	$ 225,845
Total	3,679,322	$ 3.63	$ 13,355,939	3,794,733	$ 0.75	$ 2,846,050	-	$ -	$ -	$ 2,846,050

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	306,063	$ 3.6300	$ 1,111,009	314,528	$ 0.7500	$ 235,896	-	$ 1.8500	$ -	$ 235,896
February	271,586	$ 3.6300	$ 985,857	287,720	$ 0.7500	$ 215,790	-	$ 1.8500	$ -	$ 215,790
March	284,333	$ 3.6300	$ 1,032,129	289,988	$ 0.7500	$ 217,491	-	$ 1.8500	$ -	$ 217,491
April	252,213	$ 3.6300	$ 915,533	259,765	$ 0.7500	$ 194,824	-	$ 1.8500	$ -	$ 194,824
May	329,290	$ 3.6300	$ 1,195,323	330,963	$ 0.7500	$ 248,222	-	$ 1.8500	$ -	$ 248,222
June	360,467	$ 3.6300	$ 1,308,495	372,023	$ 0.7500	$ 279,017	-	$ 1.8500	$ -	$ 279,017
July	380,602	$ 3.6300	$ 1,381,585	388,981	$ 0.7500	$ 291,736	-	$ 1.8500	$ -	$ 291,736
August	335,929	$ 3.6300	$ 1,219,422	342,698	$ 0.7500	$ 257,024	-	$ 1.8500	$ -	$ 257,024
September	302,255	$ 3.6300	$ 1,097,186	313,205	$ 0.7500	$ 234,904	-	$ 1.8500	$ -	$ 234,904
October	272,862	$ 3.6300	$ 990,489	282,646	$ 0.7500	$ 211,985	-	$ 1.8500	$ -	$ 211,985
November	297,213	$ 3.6300	$ 1,078,883	311,090	$ 0.7500	$ 233,318	-	$ 1.8500	$ -	$ 233,318
December	286,509	$ 3.6300	$ 1,040,028	301,126	$ 0.7500	$ 225,845	-	$ 1.8500	$ -	$ 225,845
Total	3,679,322	$ 3.63	$ 13,355,939	3,794,733	$ 0.75	$ 2,846,050	-	$ -	$ -	$ 2,846,050

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
February	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
March	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
April	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
May	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
June	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
July	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
August	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
September	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
October	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
November	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
December	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	306,063	$ 3.63	$ 1,111,009	314,528	$ 0.75	$ 235,896	-	$ -	$ -	$ 235,896
February	271,586	$ 3.63	$ 985,857	287,720	$ 0.75	$ 215,790	-	$ -	$ -	$ 215,790
March	284,333	$ 3.63	$ 1,032,129	289,988	$ 0.75	$ 217,491	-	$ -	$ -	$ 217,491
April	252,213	$ 3.63	$ 915,533	259,765	$ 0.75	$ 194,824	-	$ -	$ -	$ 194,824
May	329,290	$ 3.63	$ 1,195,323	330,963	$ 0.75	$ 248,222	-	$ -	$ -	$ 248,222
June	360,467	$ 3.63	$ 1,308,495	372,023	$ 0.75	$ 279,017	-	$ -	$ -	$ 279,017
July	380,602	$ 3.63	$ 1,381,585	388,981	$ 0.75	$ 291,736	-	$ -	$ -	$ 291,736
August	335,929	$ 3.63	$ 1,219,422	342,698	$ 0.75	$ 257,024	-	$ -	$ -	$ 257,024
September	302,255	$ 3.63	$ 1,097,186	313,205	$ 0.75	$ 234,904	-	$ -	$ -	$ 234,904
October	272,862	$ 3.63	$ 990,489	282,646	$ 0.75	$ 211,985	-	$ -	$ -	$ 211,985
November	297,213	$ 3.63	$ 1,078,883	311,090	$ 0.75	$ 233,318	-	$ -	$ -	$ 233,318
December	286,509	$ 3.63	$ 1,040,028	301,126	$ 0.75	$ 225,845	-	$ -	$ -	$ 225,845
Total	3,679,322	$ 3.63	$ 13,355,939	3,794,733	$ 0.75	$ 2,846,050	-	$ -	$ -	$ 2,846,050

RTSR Workform for Electricity Distributors (2014 Filers)

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	$ 0.0067	665,090,254	-	$ 4,456,105	33.4%	$ 4,457,258	$0.0067
General Service Less Than 50 kW	kWh	$ 0.0058	248,693,393	-	$ 1,442,422	10.8%	$ 1,442,795	$0.0058
General Service 50 to 4,999 kW	kW	$ 3.0721	-	2,227,931	$ 6,844,427	51.3%	$ 6,846,198	$3.0729
Large Use	kW	$ 2.8874	-	136,790	$ 394,967	3.0%	$ 395,070	$2.8881
Unmetered Scattered Load	kWh	$ 0.0058	3,814,747	-	$ 22,126	0.2%	$ 22,131	$0.0058
Street Lighting	kW	$ 1.8681	-	44,299	$ 82,755	0.6%	$ 82,776	$1.8686
Embedded Distributor	kW	$ 2.8965	-	37,867	$ 109,682	0.8%	$ 109,710	$2.8972
					$ 13,352,483			

RTSR Workform for Electricity Distributors (2014 Filers)

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

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0014	665,090,254	-	$ 931,126	32.2%	$ 916,996	$0.0014
General Service Less Than 50 kW	kWh	$ 0.0013	248,693,393	-	$ 323,301	11.2%	$ 318,395	$0.0013
General Service 50 to 4,999 kW	kW	$ 0.6740	-	2,227,931	$ 1,501,625	52.0%	$ 1,478,838	$0.6638
Large Use	kW	$ 0.6335	-	136,790	$ 86,656	3.0%	$ 85,341	$0.6239
Unmetered Scattered Load	kWh	$ 0.0013	3,814,747	-	$ 4,959	0.2%	$ 4,884	$0.0013
Street Lighting	kW	$ 0.4101	-	44,299	$ 18,167	0.6%	$ 17,891	$0.4039
Embedded Distributor	kW	$ 0.6356	-	37,867	$ 24,068	0.8%	$ 23,703	$0.6260
					$ 2,889,904			

RTSR Workform for Electricity Distributors (2014 Filers)

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	$0.0067	665,090,254	-	4,457,258.05	33.4%	$ 4,457,258	$0.0067
General Service Less Than 50 kW	kWh	$0.0058	248,693,393	-	$ 1,442,795	10.8%	$ 1,442,795	$0.0058
General Service 50 to 4,999 kW	kW	$3.0729	0	2,227,931	$ 6,846,198	51.3%	$ 6,846,198	$3.0729
Large Use	kW	$2.8881	0	136,790	$ 395,070	3.0%	$ 395,070	$2.8881
Unmetered Scattered Load	kWh	$0.0058	3,814,747	-	$ 22,131	0.2%	$ 22,131	$0.0058
Street Lighting	kW	$1.8686	0	44,299	$ 82,776	0.6%	$ 82,776	$1.8686
Embedded Distributor	kW	$2.8972	0	37,867	$ 109,710	0.8%	$ 109,710	$2.8972
					$ 13,355,939			

RTSR Workform for Electricity Distributors (2014 Filers)

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	$ 0.0014	665,090,254	-	$ 916,996	32.2%	$ 916,996	$ 0.0014
General Service Less Than 50 kW	kWh	$ 0.0013	248,693,393	-	$ 318,395	11.2%	$ 318,395	$ 0.0013
General Service 50 to 4,999 kW	kW	$ 0.6638	-	2,227,931	$ 1,478,838	52.0%	$ 1,478,838	$ 0.6638
Large Use	kW	$ 0.6239	-	136,790	$ 85,341	3.0%	$ 85,341	$ 0.6239
Unmetered Scattered Load	kWh	$ 0.0013	3,814,747	-	$ 4,884	0.2%	$ 4,884	$ 0.0013
Street Lighting	kW	$ 0.4039	-	44,299	$ 17,891	0.6%	$ 17,891	$ 0.4039
Embedded Distributor	kW	$ 0.6260	-	37,867	$ 23,703	0.8%	$ 23,703	$ 0.6260
					$ 2,846,050			

RTSR Workform for Electricity Distributors (2014 Filers)

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 descriptions for the RTSRs are transfered automatically from Sheet 4 to Sheet 11, Column A.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0067	$ 0.0014
General Service Less Than 50 kW	kWh	$ 0.0058	$ 0.0013
General Service 50 to 4,999 kW	kW	$ 3.0729	$ 0.6638
Large Use	kW	$ 2.8881	$ 0.6239
Unmetered Scattered Load	kWh	$ 0.0058	$ 0.0013
Street Lighting	kW	$ 1.8686	$ 0.4039
Embedded Distributor	kW	$ 2.8972	$ 0.6260

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Month/Year	Account Balance		
	All Classes	Carrying Charges *	Account Balance
January 2011	12,026	-	12,026
February 2011	24,053	14	24,066
March 2011	36,079	30	36,123
April 2011	48,105	44	48,192
May 2011	60,132	60	60,279
June 2011	72,158	73	72,378
July 2011	84,184	90	84,494
August 2011	96,211	105	96,626
September 2011	108,237	116	108,768
October 2011	120,263	135	120,930
November 2011	132,289	145	133,101
December 2011	144,316	165	145,293
January 2012	164,117	180	165,274
February 2012	183,919	191	185,267
March 2012	203,721	229	205,298
April 2012	223,523	245	225,345
May 2012	243,324	278	245,425
June 2012	263,126	293	265,520
July 2012	282,928	328	285,649
August 2012	302,729	352	305,803
September 2012	322,531	365	325,969
October 2012	342,333	402	346,173
November 2012	362,134	412	366,387
December 2012	381,936	451	386,639
January 2013	381,936	477	387,116
February 2013	381,936	431	387,547
March 2013	381,936	477	388,024
April 2013	381,936	461	388,485
May 2013	381,936	477	388,962
June 2013	381,936	461	389,424
July 2013	381,936	477	389,900
August 2013	381,936	477	390,377
September 2013	381,936	461	390,839
October 2013	381,936	477	391,316
November 2013	381,936	461	391,777
December 2013	381,936	477	392,254
Totals	**381,936**	**10,318**	**392,254**

Month/Year	Residential			GS<50kW			GS>50kW			
	kWh Savings	Carrying Charges *	Account Balance	kWh Savings	Carrying Charges *	Account Balance	kWh Savings	Carrying Charges *	Account Balance	
January 2011	2,942		2,942	6,313		6,313	2,771		2,771	
February 2011	5,884	3	5,887	12,627	7	12,634	5,542	3	5,545	
March 2011	8,826	7	8,837	18,940	16	18,963	8,313	7	8,323	
April 2011	11,768	11	11,789	25,253	23	25,299	11,084	10	11,104	
May 2011	14,710	15	14,746	31,566	32	31,644	13,855	14	13,889	
June 2011	17,652	18	17,706	37,880	38	37,995	16,626	17	16,677	
July 2011	20,594	22	20,670	44,193	47	44,356	19,398	21	19,469	
August 2011	23,536	26	23,637	50,506	55	50,724	22,169	24	22,264	
September 2011	26,478	28	26,608	56,819	61	57,098	24,940	27	25,062	
October 2011	29,420	33	29,583	63,133	71	63,482	27,711	31	27,864	
November 2011	32,362	36	32,560	69,446	76	69,872	30,482	33	30,669	
December 2011	35,304	40	35,543	75,759	87	76,272	33,253	38	33,478	144,315.76
January 2012	40,129	44	40,412	83,952	94	84,559	40,037	41	40,303	
February 2012	44,953	47	45,283	92,145	98	92,850	46,821	47	47,134	
March 2012	49,778	56	50,164	100,338	115	101,158	53,605	58	53,976	
April 2012	54,603	60	55,049	108,531	121	109,471	60,389	65	60,825	
May 2012	59,428	68	59,941	116,724	135	117,799	67,173	75	67,684	
June 2012	64,253	72	64,838	124,917	141	126,133	73,957	81	74,549	
July 2012	69,077	80	69,743	133,109	156	134,481	80,741	92	81,425	
August 2012	73,902	86	74,653	141,302	166	142,840	87,525	101	88,309	
September 2012	78,727	89	79,567	149,495	170	151,203	94,309	105	95,199	
October 2012	83,552	98	84,490	157,688	186	159,582	101,093	117	102,100	
November 2012	88,377	101	89,416	165,881	190	167,965	107,877	122	109,006	
December 2012	93,201	110	94,350	174,074	207	176,365	114,661	134	115,924	237,620.33
January 2013	93,201	116	94,467	174,074	217	176,582	114,661	143	116,067	
February 2013	93,201	105	94,572	174,074	196	176,778	114,661	129	116,197	
March 2013	93,201	116	94,688	174,074	217	176,996	114,661	143	116,340	
April 2013	93,201	113	94,801	174,074	210	177,206	114,661	139	116,478	
May 2013	93,201	116	94,917	174,074	217	177,423	114,661	143	116,622	
June 2013	93,201	113	95,030	174,074	210	177,634	114,661	139	116,760	
July 2013	93,201	116	95,146	174,074	217	177,851	114,661	143	116,903	
August 2013	93,201	116	95,263	174,074	217	178,068	114,661	143	117,046	
September 2013	93,201	113	95,375	174,074	210	178,279	114,661	139	117,185	
October 2013	93,201	116	95,492	174,074	217	178,496	114,661	143	117,328	
November 2013	93,201	113	95,604	174,074	210	178,706	114,661	139	117,467	
December 2013	93,201	116	95,721	174,074	217	178,923	114,661	143	117,610	
Totals	**93,201**	**2,519**	**95,721**	**174,074**	**4,849**	**178,923**	**114,661**	**2,949**	**117,610**	**392,253.86**

* 1.47% Board Prescribed Rate

381,936.09

Total LRAM Claim - balance as of December 31, 2012	**381,936**
Carrying Charges to December 31, 2012	**4,703**
Carrying Charges to December 31, 2013	**5,614**
Total LRAM Claim with carrying charges to December 31, 2013	**392,254**

392,253.86

Res	24.40%
GS<50	45.61%
GS>50	29.98%

Kitchener Wilmot Hydro. LRAMVA

OPA Conservation & Demand Management Programs

Initiative Results at End-User Level

For: Kitchener Wilmot Hydro

			2011				2012							
Initiative Name	**Program Year**	**Results Status**	**Net Summer Peak Demand Savings (kW)**	**Net Energy Savings (kWh)**	**Gross Summer Peak Demand Savings (kW)**	**Gross Energy Savings (kWh)**	**Net Summer Peak Demand Savings (kW)**	**Net Energy Savings (kWh)**	**2010 Rate (effective May 1)**	**2011 Rate (effective May 1)**	**2012 Rate (effective May 1)**	**2011 LRAMVA**	**2012 LRAMVA**	
Pre-2011 PROGRAMS COMPLETED IN 2011														
General Service <50kW														
High Performance New Construction	2010	Final	10.02	13,024	2.04	10,461	81.02	32,828	0.0122	0.0122	0.0123	$ 158.90	$ 402.69	
Electricity Retrofit Incentive	2010	Final	315.90	2,150,912	532.28	3,581,093	315.90	2,150,912	0.0122	0.0122	0.0123	$ 26,241.12	$ 26,384.52	
GENERAL SERVICE <50kW TOTAL			**325.91**	**2,163,936**	**534.31**	**3,591,554**	**396.91**	**2,183,740**				**$ 26,400.02**	**$ 26,787.21**	
General Service >50kW to 4,999kW														
Electricity Retrofit Incentive	2010	Final	655.64	4,474,416	1,131.09	7,609,822	655.64	4,474,416	3.9737	3.9888	4.0319	$ 31,342.96	$ 31,608.63	
GENERAL SERVICE >50kW to 4,999kW TOTAL			**655.64**	**4,474,416**	**1,131.09**	**7,609,822**	**655.64**	**4,474,416**				**$ 31,342.96**	**$ 31,608.63**	
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			**981.55**	**6,638,352**	**1,665.40**	**11,201,376**	**1,052.55**	**6,658,156**				**$ 57,742.98**	**$ 58,395.84**	
OPA PROGRAM RESULTS														
Residential Service														
Appliance Retirement	2011	Final	35.96	262,506	72.00	520,136	35.96	262,506	0.0169	0.0170	0.0172	$ 4,453.86	$ 4,497.61	
Appliance Exchange	2011	Final	6.99	8,561	13.56	16,611	6.99	8,561	0.0169	0.0170	0.0172	$ 145.25	$ 146.68	
HVAC Incentives	2011	Final	533.92	984,607	881.76	1,642,063	533.92	984,607	0.0169	0.0170	0.0172	$ 16,705.50	$ 16,869.60	
Conservation Instant Coupon Booklet	2011	Final	18.90	310,175	16.59	279,117	18.90	310,175	0.0169	0.0170	0.0172	$ 5,262.64	$ 5,314.34	
Bi-Annual Retailer Event	2011	Final	29.43	514,924	26.09	467,145	29.43	514,924	0.0169	0.0170	0.0172	$ 8,736.54	$ 8,822.36	
Residential Demand Response														
Appliance Retirement	2012	Final					20.00	134,960	0.0169	0.0170	0.0172		$ 2,312.31	
Appliance Exchange	2012	Final					8.00	14,106	0.0169	0.0170	0.0172		$ 241.68	
HVAC Incentives	2012	Final					401.00	689,786	0.0169	0.0170	0.0172		$ 11,818.33	
Conservation Instant Coupon Booklet	2012	Final					4.00	22,805	0.0169	0.0170	0.0172		$ 390.73	
Bi-Annual Retailer Event	2012	Final					24.00	436,812	0.0169	0.0170	0.0172		$ 7,484.05	
Residential Demand Response	2012	Final												
RESIDENTIAL TOTAL			**625.20**	**2,080,773**	**1,009.99**	**2,925,072**	**1,082.20**	**3,379,242**				**$ 35,303.79**	**$ 57,897.69**	**$ 93,201.48**
General Service <50kW														
Efficiency: Equipment Replacement	2011	Final	608.00	3,347,968	818.70	4,383,752	608.00	3,347,968	0.0122	0.0122	0.0123	$ 40,845.21	$ 41,068.41	
Direct Install Lighting	2011	Final	267.91	647,504	289.48	697,336	267.91	647,504	0.0122	0.0122	0.0123	$ 7,899.55	$ 7,942.72	
Demand Response 3	2011	Final					0.00	-	0.0122	0.0122	0.0123	$ -	$ -	
Small Commercial Demand Response	2011	Final					0.00	0	0.0122	0.0122	0.0123	$ -	$ -	
Efficiency: Equipment Replacement	2012	Final					189.00	1,000,001	0.0122	0.0122	0.0123	$ -	$ 12,266.68	
Direct Install Lighting	2012	Final					170.00	624,605	0.0122	0.0122	0.0123	$ -	$ 7,661.82	
Demand Response 3	2012	Final					580.00	8,426	0.0122	0.0122	0.0123	$ -	$ 103.36	
New Construction	2012	Final					30.00	51,506	0.0122	0.0122	0.0123	$ -	$ 631.81	
Energy Audit	2012	Final	10.00	50,353	10.00	50,353	31.00	151,058	0.0122	0.0122	0.0123	$ 614.31	$ 1,852.98	
GENERAL SERVICE <50kW TOTAL			**885.91**	**4,045,825**	**1,118**	**5,131,441**	**1,875.91**	**5,831,068**				**$ 49,359.07**	**$ 71,527.77**	**$120,886.83**
General Service 50 to 4,999 kW														
Efficiency: Equipment Replacement (Industrial)	2011	Final	39.95	271,185	53.84	359,559	39.95	271,185	3.9737	3.9888	4.0319	$ 1,909.92	$ 1,926.11	
Demand Response 3	2011	Final					0.00	0	3.9737	3.9888	4.0319	$ -	$ -	
Efficiency: Equipment Replacement	2012	Final					993.00	3939416	3.9737	3.9888	4.0319	$ -	$ 47,872.93	
Efficiency: Equipment Replacement (Industrial)	2012	Final					0.00	0	3.9737	3.9888	4.0319	$ -	$ -	
Demand Response 3	2012	Final							3.9737	3.9888	4.0319	$ -	$ -	
GENERAL SERVICE 50 to 4,999 kW			**39.95**	**271,185**	**53.84**	**359,559**	**1,032.95**	**4,210,601**				**$ 1,909.92**	**$ 49,799.03**	**$ 51,708.95**
TOTAL LRAMVA - OPA PROGRAM RESULTS			**1,551.06**	**6,397,784**	**2,182.02**	**8,416,072**	**3991.06**	**13,420,912**				**$ 86,572.78**	**$179,224.49**	
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			**981.55**	**6,638,352**	**1,665.40**	**11,201,376**	**1,052.55**	**6,658,155.74**				**$ 57,742.98**	**$ 58,395.84**	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**1,551.06**	**6,397,784**	**2,182.02**	**8,416,072**	**3,991.06**	**13,420,911.66**				**$ 86,572.78**	**$179,224.49**	
			2,532.61	**13,036,135**	**3,847.41**	**19,617,448**	**5,044**	**20,079,067**				**$144,315.76**	**$237,620.33**	$381,936.09