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March 4, 2014

Delivered By Courier and RESS

Ontario Energy Board
P.O. Box 2319
27th Floor, 2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Kirsten Walli
Board Secretary

Re: Haldimand County Hydro Inc. (EB-2013-0134)
2014 Cost of Service Electricity Distribution Rate Application
Responses to Interrogatories

Dear Ms. Walli:

Haldimand County Hydro Inc. filed an application with the Ontario Energy Board (the "Board") on November 15, 2013 seeking approval for changes to rates that it may charge for electricity distribution to be effective May 1, 2014.

Pursuant to Procedural Order No. 2 ("PO2") issued on January 29, 2014, Board Staff and Intervenors filed interrogatories on February 6, 2014 and February 12, 2014, respectively.

In accordance with PO2, two hard copies of the complete responses to all interrogatories are now enclosed. An electronic copy of the complete responses in PDF format and required models in Excel format will have been submitted through the Board's *Regulatory Electronic Submission System* ("RESS").

All of which is respectfully submitted for the Board's consideration.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by

Jacqueline A. Scott
Finance Manager

cc: Intervenors on Record (by email):

- Energy Probe Research Foundation – c/o Randy Aiken
- Energy Probe Research Foundation – c/o David MacIntosh
- Vulnerable Energy Consumers Coalition – c/o Michael Janigan
- Vulnerable Energy Consumers Coalition – c/o Mark Garner
- Vulnerable Energy Consumers Coalition – c/o Bill Harper

Haldimand County Hydro Inc. ("HCHI")
EB-2013-0134
INTERROGATORY RESPONSES

1 Foundation

1.1 Does the planning (regional, infrastructure investment, asset management, etc.) undertaken by the applicant and outlined in the application support the appropriate management of the applicant's assets?

1.1 Staff 1. REG Plan

Reference: Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, p. 11 of 66

It appears that neither HONI nor the OPA have commenced regional planning that would affect HCHI. However, HCHI indicates that on the topic of Regional Infrastructure Planning it responded to Hydro One's request of September 11, 2013 regarding future transmission connections. Please provide a copy of the October 17, 2013 email response by HCHI.

<u>HCHI Response</u>

The following is a copy of the October 17, 2013 email exchange between Hydro One Networks Inc. ("HONI") and Haldimand County Hydro Inc. ("HCHI"):

"From:	Paul Heeg
Sent:	October-17-13 3:54 PM
To:	'LargeAccounts@hydroone.com'
Subject:	RE: Regional Infrastructure Planning Launch & Amendments to the TSC/DSC
Attachments:	RE: Regional Infrastructure Planning Launch & Amendments to the TSC/DSC; Regional Planning Status...

Dear Mr. Bing Young,
Director, Transmission System Development
Asset Management
Hydro One Networks Inc.

Thank you for your email and request for Haldimand County Hydro Inc. (HCHI) to participate in the Regional Infrastructure Planning process. HCHI has identified (attached email dated September 16, 2013) that HCHI was not listed in "Appendix B: List of LDCs for Each Region" as a participating LDC in the Niagara Region. We have received a revised Appendix B with the changes (attached email dated September 19, 2013).

In your email dated September 5, 2013, you had requested "information regarding whether you foresee a potential need for additional transmission connection capacity to support the needs of your distribution system and of the distribution system of any embedded license distributor in your system over the next five years". In response to this question, HCHI at this time, does not foresee a potential need for additional transmission connection capacity to support the load needs of our distribution system and of the distribution system of any embedded license distributor in our system over the next five years assuming the completion of the Dunnville TS re-build project with an in-service date of June 2015. However, transmission connection capacity for generation connections to Dunnville TS (Niagara Region) have constraints and these transmission constraints may not be removed with the Dunnville TS refurbishment project. HCHI cannot accommodate generation connections in the area serviced by Dunnville TS because of these transmission constraints.

We look forward to participating in the Regional Infrastructure Planning process.

Sincerely,

Paul Heeg
Engineering Manager
Haldimand County Hydro Inc.
Tel: (905) 765 5211 x 2247
Fax: (905) 765 5914

From: LargeAccounts@hydroone.com [mailto:LargeAccounts@hydroone.com]
Sent: September-05-13 1:44 PM
To: Paul Heeg
Subject: Regional Infrastructure Planning Launch & Amendments to the TSC/DSC
Regional Infrastructure Planning Launch & Amendments to the Transmission System Code and Distribution System Code
Haldimand County Hydro Inc.'s Review & Feedback Requested

Dear Mr. Paul Heeg:

This letter formally launches the Regional Infrastructure Planning process in accordance with the Ontario Energy Board's (OEB) "Amendments to the Transmission System Code and Distribution System Code", dated August 26, 2013. The OEB TSC and DSC amendments are intended to support the Regional Infrastructure Planning process described in the Planning Process Working Group (PPWG) Report. As indicated in the OEB Notice, it is the Board's expectation that transmitters and LDCs will follow the process set out in the PPWG Report. The documents noted above can be accessed from the OEB website:

Notice to Amend TSC / DSC
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011
043/Notice_Amend_TSC_DSC_EB-2011-0043.pdf

PPWG Report
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Regional%20Planning/Regional%20Infrastructure%20Planning%20-%20Working%20Groups#20130517

As identified in the PPWG Report, 21 Regions have been established on a preliminary basis for undertaking Regional Planning. The 21 Regions have been placed into three prioritization groups based on need and planning activities already identified or under consideration. Maps showing the 21 Regions/Groups and a table which includes a list of LDCs in each Region is attached in Appendix A and B respectively. Please review the list to confirm that your LDC is placed in the appropriate Region(s).

As set out in the TSC and DSC amendments noted above, we also request information regarding whether you foresee a potential need for additional transmission connection capacity to support the needs of your distribution system and of the distribution system of any embedded license distributor in your system over the next five years. The purpose of this information is to assist us in ascertaining if the preliminary prioritization of the regions needs to be refined for the purpose of the transition to regional planning for all regions. You are also welcome to provide further information and/or comments that you feel may be useful in terms of our review and potential refinement of the prioritization of the 21 regions within the three groups outlined in the PPWG Report.

We will appreciate your response as soon as possible and no later than 45 days (October 20, 2013) as set out in section 8.5.1 of the DSC. Please forward your information via email to the following email address – cbrlargeaccounts@HydroOne.com. After receiving inputs from all LDCs, Hydro One will complete a review of all regions and prioritization (within 45 days) to revise it to reflect emerging needs in the regions.

Hydro One looks forward to working with you in executing the Regional Infrastructure Planning
process.

Sincerely,

Bing Young
Director, Transmission System Development
Asset Management
Hydro One Networks Inc.
Phone: (416)345-5029
Bing.Young@HydroOne.com”

1.1 Staff 2. REG Plan

Reference: Appendix "D" to Exhibit 2 Appendix "A" – OPA Letter of Comment

In the OPA Letter of comment, the OPA states that it has received and offered 214 microFIT contracts and 11 FIT contracts, of which 17 have not yet been connected. Does HCHI foresee the need for additional transmission capacity for the additional projects not yet connected?

<u>HCHI Response</u>

The generation projects that have been offered contracts and not yet connected are in the process of assessment, procurement or construction. The new FIT 3.0 rules' process does not allow for offering contracts if there is no capacity. HCHI's distribution territory is divided into two separate regions 1) Burlington – Nanticoke and 2) Niagara. HCHI does not foresee Transmission upgrades required in the Burlington Nanticoke region. The Niagara Region (Dunnville TS) currently has Transmission constraints that prevent generation projects from connection in that area. HCHI understands that Hydro One is in the process of removing these Transmission constraints.

1.1 Staff 3. Capital Expenditure Plan Prioritizations

Reference: ***Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, p. 17 of 66***

HCHI states that its Discretionary Capital Projects Prioritization Model calculates a delta risk score which is used to compare projects on a dollar cost per unit value of delta risk. The delta risk is determined by comparing a series of Business Values on a before and after basis for each project. Each business value is associated with a Business Value Attribute. Table 5 – 1 shows weights for each of the business values. From the table:

a. Please explain the factors considered in each of the Business Value Attributes.

HCHI Response

The "Discretionary" Capital Projects Prioritization Model (the "Model") was prepared by Kinectrics Inc. for HCHI and included as part of the 2010 Cost of Service rate application. The Model is included in the DS Plan as Appendix E as part of the 2014 Cost of Service Electricity Distribution Rate Application Exhibit 2 – Rate Base – Appendix A. The Business Values and Business Value Attributes are described in section 5.2.3 Performance Measurement for Continuous Improvement of the DS Plan. Below is the excerpt from the DS Plan:

> "In preparation for the 2010 COS Distribution Rate Application, Kinectrics Inc. prepared for HCHI a *Discretionary Capital Projects Prioritization Model* dated March 12, 2009, Kinectrics Inc. Report No K-014704-RA-0002-R02 (Appendix E). The model has been used to evaluate discretionary capital projects that are in the System Service or System Renewal category for the years 2010 to 2014. Other capital expenditures in the System Access or General Plant categories have not been run through the model because they are customer demand type expenditures or based on other analysis such as the five year IT plan or fleet management schedule.

The model is based on a series of business values that describe the corporation's main goals, and objectives. Each business value is rated based upon the effect on attributes about the distribution system before and anticipated after the project is constructed. The risk score is weighted for each business value and a delta risk score is calculated. The cost of the project is then divided by the delta risk value to produce a dollar cost per unit value of delta risk. This method of evaluating each project allows the dollar cost per unit value of delta risk to be compared against other projects. Ideally the lower the dollar cost per delta risk value the more attractive the project will be.

The model considers six (6) business values and the attributes of these values are called business value attributes. These values have been defined in reference to Haldimand County Utilities Inc.'s Strategic Plan developed in 2006. They have been assigned weights to reflect their impact on HCHI's business and illustrated in Table 5 – 1.

Table 5 – 1

Business Values and Business Value Attribute

Business Value (BV)	Business Value Attribute (BVA)	Weight (% of Total)
Business Efficiency	Status of Detailed Project Design	10
Reliability Performance	Impact on SAIDI and SAIFI	25
	Impact on Voltage	
Community Relations	Community Impact	20
Safety	Eliminating Preventable Public Accidents	25
	Eliminating Preventable Work Place Accidents	
	Managing Property Damage Claims	
Regulatory Interface	Regulatory Compliance	10
Environmental Stewardship	Environmental Spills	10

In addition to the above business values, some projects have direct financial savings. These savings are derived from the fact that HCHI is levied a "Sub-transmission (ST)" (formerly called Low Voltage) charge from HONI when HCHI's customer is fed from HONI's distribution plant. The present value of these savings is used to offset the cost of the project before a dollar per delta risk score is calculated. Although the savings do not reflect that HCHI will incur costs to maintain the new distribution assets, it is felt that an offset is still relevant.

It should be noted that sustainment type projects are not evaluated using the *Prioritization Model*. Sustainment projects are not discretionary because an existing asset is at the end of its useful life and must be replaced."

b. Please explain the establishment of the weight assigned to each Business Value.

<u>HCHI Response</u>

See response to question a) and excerpt below from the report prepared by Kinectrics Inc. for HCHI.

"HCHI-SPECIFIC MATRICES FOR PRIORITIZING "DISCRETIONARY" CAPITAL PROJECTS

3.1 Likelihood and Consequence Risk Matrix

Table 3-1 shows a generic Likelihood vs. Risk Consequence Matrix. A value in each cell is calculated as ex (with x=1, 2, 3, 4 or 5, depending on the perceived risk consequence) multiplied by the likelihood (0.1 for very unlikely, 0.25 for unlikely, etc.)and then normalized so that the least likely lowest risk score is =1.

Table 3-1 Likelihood and Consequence Risk Matrix

LIKELIHOOD/CONSEQUENCE	SMALL	MODERATE	SIGNIFICANT	SEVERE	THE WORST CASE
Most Likely (>90%)	9	25	68	184	500
Very Likely (>75%)	8	21	56	153	417
Likely (50/50)	5	14	38	102	278
Unlikely (<25%)	3	7	19	51	139
Very Unlikely (<10%)	1	3	7	20	56

3.2 Business Values and Associated Consequences

The methodology described in the previous section was customized with the significant input from HCHI's senior staff to properly reflect HCHI's BVs, associated Weights and BVAs, and perceived project-specific alleviated risks. Table 3-2 shows the resultant matrix.

"DISCRETIONARY" CAPITAL PROJECTS PRIORITIZATION for Haldimand County Hydro Inc.

Table 3-2 HCHI-Specific BVs, BVAs and Risk Consequences Matrix

Project Specific Risk Consequences

Business Value (BV)	Weight	Business Value Attribute (BVA)	The Worst Case (All BVs except BE) (Highest Avoided Risk for BE)	Severe (All BVs Except BE) (Most Risk to BE Avoided)	Significant (All BVs except BE) (Medium Risk to BE)	Moderate (All BVs Except BE) (Significant Risk to BE)	Small (All BVs Except BE) (Highest Risk to BE)
1. Business Efficiency (BE)[Note 2]	10%	- Status of Detail Project Design	Exact Cost is Known, e.g. Purchase of Assets from Another Utility	Detailed best possible design done,actual cost expected to be within ±10% of estimate	Fairly detailed design done, actual cost is expected to be within ±25% of estimate	Some detailed design done, actual cost expected to be within ±50% of the estimate	Very preliminary design done, actual cost may be 50-100% higher than estimate
2. Reliability Performance	25%	- Impact on SAIDI and SAIFI	Significant future increaseof local contribution to SAIFI and/or SAIDI resulting in Regulatory non-compliance	Significan future increase of local contribution to SAIFI and/or SAIDI	Small future increase of local contribution to SAIFI and/or SAIDI	No future change from existing local contribution to SAIFI and/or SAIDI	Small future reduction of local contribution to SAIFI/SAIDI
		- Impact on Voltage		Voltage outside of the CSA "extreme" range	Voltage outside of the CSA "normal" range but within the CSA "extreme" range		
3. Community Relations	20%	- Community Impact	Big negative Impact on Community, i.e. dealy of road construction work, if project is not done	Some negative impact on Community, e.g. known poublic concern with existing system condition	Negative impact mitigated and several customers oppose the project	Negative impact mitigated and very few customers still oppose the porject	
4. Safety	25%	- Eliminating Preventable Public Accidents	More than one accident involving member of the public	A single accident involving member of the public			
		- Eliminating Preventable Work Place Accidents	More than one accident involving HCHI staff	A single accident involving HCHI staff			
		- Managing Property Damage Claims	Future local property claims increase by more than 100% over 3-year rolling average	Future local property claims increase by 50% to 100% over 3-year rolling average	Future local property claims increase by 25% to 50% over 3-year rolling average	Future local property claims increase by 10% to 25% over 3-year rolling average	Future local property claims increase by less than 10% over 3-year rolling average
5. Regulatory Interface	10%	- Regulatory Compliance	Complete loss of credibility and Regulatory compliance is closely monitored by the Regulatory Authority(s)	Penallties are imposed by a Regulatory Authority(s)	Non-compliance results in Regulatory Authority(s) complaint to the President and/or the Board of Directors	Non-compliance resolved with the President's involvement	Non-compliance resolved by the technical staff
6. Environmental Stewardship	10%	- Environmental Spills	Major spill in a sensitive area	Minor spill in a sensitive area	Major spill outside of a sensitive area	Minor spill outside of a sensitive area	

Note 1. The Risk Consequences and their likelyhood need to be assessed for the existing condition and then assuming the project were completed. The weighted sum of the differentces for all the BVs is the Risk Score Change (RSC).

Note 2. For Business Efficiency, not doing the project has NO risk of overspending. The better quality of an estimate, the more of "overspending" risk is eliminated, i.e. the best estimate eliminates the highst risk.The score for the avoided risk should be added to the calculated Delta (BEFORE-AFTER)

Note 3. For some of the BVAs fewer than 5 Risk Consequence categories are applicable

— 8 —

K-014704-RA-0002-R012

"

c. Does HCHI strictly adhere to the priorities established by the model, or is there additional prioritization after the model is applied?

HCHI Response

HCHI adheres to the Model as the projects are prepared for inclusion into the following year's capital budget. There have been times where capital expenditures have been approved by the HCHI Board of Directors to address a need where additional prioritization is given to a project.

d. If there is additional prioritization, please explain these additional actions and why they are necessary

HCHI Response

Additional prioritization is given to projects that involve a severe power quality and capacity issue in a particular area. The only solution is to rebuild infrastructure by converting to a higher voltage or adding additional load capacity by other means. This type of prioritization is typically under extreme or emergency conditions.

e. Please explain the linkages between HCHI's selected business value attributes and customer value, customer preferences, operational effectiveness, financial performance and delivery on public policy objectives.

<u>HCHI Response</u>

HCHI has been the Model for discretionary capital projects in the years 2010 to 2014. HCHI recognizes that the Model requires modifications for better linkages to reflect the customer value, customer preferences, operational effectiveness, financial performance and delivery on public policy objectives. The model has not to date been modified to align with the Board's Chapter 5 Filing Requirements, but is expected to occur in 2014 for 2015 capital projects.

1.1 Staff 4. REG Plan

Reference: Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, p15 of 66–Transmission Connected Generation Facilities

HCHI lists four Transmission-Connected Renewable Energy Projects that require temporary and permanent distribution connection and relocation work. One project has been granted a leave to construct (EB-2011-0063). However, HCHI states that these projects have not been included in this DS Plan.

a. Please update the DS Plan so that these projects are included in the CAPEX planned for 2014 – 2018.

HCHI Response

All of HCHI's costs are recovered from the Transmission Connected proponents for the relocation of HCHI distribution assets.

The intent of the statement "*these projects have not been included in this DS Plan*" was to illustrate that these new and relocated lines present opportunities for HCHI to plan and construct new lines to close gaps to create loops and alternate feeds. The planning at this stage is too preliminary to include projects and estimates for the purposes of including in the CAPEX and updating the DS Plan. The areas that HCHI may plan to convert its distribution system to 27.6 kV have not been fully reviewed. These projects would be included in the total CAPEX and prioritized. These projects are not in addition to what is contained in the DS Plan.

b. Please state the estimated capital costs for the distribution portions of the projects, the generator customer's capital contributions toward them and the portion that would be considered a provincial benefit.

HCHI Response

The project costs referenced in the Transmission Connected projects are not part of the renewable energy generation costs and therefore are not considered as part of the provincial benefit. The plant relocations are paid 100% by the Transmission connected proponents. Line extensions and expansions to connect station services are treated in accordance with the Distribution System Code ("DSC") Section 3.2 Expansions as the related new services are treated as load customers and not generator customers.

c. Please state the expected in-service date for the completion of the projects.

HCHI Response

If the question is referring to the in-service date of the transmission connected projects, HCHI has no direct involvement with transmission connected projects' Commercial Operation Dates; however HCHI staff were able to determine from publicly available information the following dates:

- Summerhaven Wind Energy Center service date of September 25, 2013.
- The Port Dover Nanticoke Wind service date of November 7, 2013.
- The Grand Renewable Energy Park has a planned Commercial Operation Date of September 2014.
- The Niagara Region Wind Corporation project has a "Leave to Construct" (EB-2013-0203) application with the Board and a Commercial Operation Date could not be found by HCHI.

1.1 Staff 5. RRFE Deliverable

Reference: ***Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, p44 of 66 – Life Cycle Activities***

HCHI has provided a table identifying four types of capital expenditures, including costs associated with retirements. Board staff is interested in how the categories relate to the categories required by Chapter 5 and found in Appendix 2-AB.

a. Please indicate in the following table whether and how the two different views of asset investments overlap or coincide. Please provide an

	System Access	System Renewal	System Service	General Plant
Sustainment				
Betterment				
Extension				
Retirement				

explanation for each alignment.

<u>HCHI Response</u>

	System Access	System Renewal	System Service	General Plant
Sustainment		yes		
Betterment	yes	yes	yes	
Extension	yes			
Retirement		yes	yes	yes

Sustainment activities involve replacing assets that are considered at the "end of service life". These investments are categorized as System Renewal. For example, pole replacments as a result of the *Distribution System Maintenance and Inspection Program* have been historically categorized as System Renewal investments. Forecast investments in System Renewal also include U/G XLPE cable replacements identified as at “end of service life” in the Asset Condition Assessment.

Betterment activities can overlap the System Access, System Renewal and System Service categories. There are various drivers of a betterment activity:

- Driver from a new customer connection (System Access);
- Driver from a System Renewal pole replacement. For example, one or two poles may be located on private property where access is difficult. The relocation of these poles to an accessible location on the road allowance may cause a trasformer replacement(s), the installation of new secondary conductor, etc. The additional activities above and beyond the pole replacment would be considered a betterment; and
- Driver from a System Service activity. Acitivities may be driven by a hazard or safety issue that was identified by HCHI’s *Distribution System Maintenance and Inspection Program* or a trouble report by the Operations Department. This driver could cause a capacity upgrade to the system involving increase pole height, upgraded conductor, additional phases or conversion to a higher voltage.

Extension activities (i.e System Access) involve building a new asset where none previously existed. This activity increases the distribution system footprint. An example of this is the construction of a line or circuit where none previously existed.

Retirement activities remove an asset from the distribution system. For example, removing an asset from service after a new asset is constructed or purchased. Generally, the distribution system footprint is not reduced. Retirements could occur over the three investment categories.

b. HCHI states that in the category Extension, Non customer-related activities are non-discretionary. Please explain Non customer-related activities and why they are considered to be non-discretionary.

<u>HCHI Response</u>

In the category Extension, Non customer-related activities are non-discretionary. Government policy delivery activities for the purposes of this discussion would be a non-customer-related activity although they affect all customers, similar to billing and associated overheads. Another example would be a project related to safety.

c. Please clarify the difference between customer and non-customer activities. As an example, does HCHI consider safety, government policy delivery, or billing and associated overheads as customer related activity?

HCHI Response

HCHI considers a customer related activity as one that satisfies the need of an individual customer.

d. From the perspective of establishing a scorecard for executive and regulatory oversight, how would HCHI tie their asset management goals in each lifecycle category to a scorecard?

HCHI Response

HCHI has not established a scorecard per se for executive and regulatory oversight nor has it tied asset management goals to the scorecard. However, HCHI does review a number of metrics to establish and monitor the overall success of its maintenance and capital programs. These metrics are discussed in the DS Plan Section 5.2.3. and include:

- OEB Service Quality Indicators
- Smart Meter Infrastructure Service Levels and data outputs
- Electrical Safety Authority compliance
- Outage indices (SAIFI,SAIDI)
- Feeder performance indices
- System losses

1.1 Staff 6. Distribution Asset Management Plan

Reference: ***Appendix H to Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, – Distribution System Maintenance and Inspection Plan***

On page 3 of the Distribution Asset Management Plan, in the second paragraph, it states that Kinectrics Inc.'s conclusions in the 2009 study "are based on available information, expert opinion and one-day field observations."

a. **Was there a series of one day visits?**

HCHI Response

The 2009 Distribution Asset Condition Assessment (Kinectrics Report K-014704-RA-0001-R012) indicates at page 1 "*one-day of field observations conducted jointly by Kinectrics and HCHI staff*".

b. **Please describe field verification involvement for the 2013 report. In particular please indicate the extent of field examinations for verifications, and compare with the one day inspection that is reflected in the 2009 report.**

HCHI Response

The Scope of Work for the 2013 report did not include field verification as more data was available than in 2009 as more inspections had been completed, no concerns were identified in 2009 with the accuracy of asset lists and condition information. As no field verification was completed in 2013 no comparison can be made to the field verifications or one day inspection reflected in the 2009 report.

1.1 Staff 7. Distribution Asset Condition Assessment

Reference: ***Appendix G to Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013 – Distribution Asset Condition Assessment***

Table 3 in Appendix G at page xix is the Year 1 Condition-Based "Flagged for Action" Plan. Board staff would like some clarifications.

a. Condition-Based "Flagged for Action Plan" (Executive Summary, Table 3 on page xix) shows that no distribution substation transformers are flagged for action for year 1, and Figure 1-5 on page 47 shows that a transformer is targeted for replacement in 3 years. However, Board staff noted that:

- **Distribution transformers have the lowest health index of all assets listed**
- **Table 1-9 on page 46 of the report shows that a spare transformer (Jarvis) is flagged for action in zero years and another (Selkirk South) is flagged for year 3.**
- **Conclusions and Recommendation #4 (on page xxi) advises that distribution transformers be addressed in an expedient manner because, although only spares are affected, this is a crucial item with major consequences of failure.**

Please clarify if a distribution transformer is planned for immediate refurbishment or replacement, and if year 0 been omitted from Figure 1-5?

HCHI Response

Year "0" has not been omitted from Figure 1-5. The use of year "0" by Kinectrics is based on the Health Index for TP1021T6 of 7% which indicates that immediate replacement is recommended in advance of even Year 1 (2014).

If these two spare transformers are removed from the Average Health index in Table 2 Page xvii and recalculated the Average Health Index improves to 77.5%.

These two transformers (TP1008T7 and TP1021T6) are each 2 MVA and were retained as spares after a previous station dismantling; all other HCHI station transformers are 5 MVA. If an in-service station transformer were to fail it is not possible to fully carry the station load with these spare transformers and they would be an interim measure at best, combined with either switching to offload the station where possible and/or rotational load shedding, until such time as a mobile distribution station could be located and brought into service and remain in use until such time as permanent replacement of the station transformer could be arranged. The spare transformer at Jarvis DS (TP1021T6) is not connected electrically to the distribution system. The spare transformer at Selkirk is connected electrically to the distribution system and has been used successfully as recently as 2012 and 2013 to offload the station in conjunction with switching to the HONI Argyle DS to allow isolation of the station for maintenance and repairs.

HCHI does have a plan to replace these spare transformers. In the CAPEX forecast in Appendix K on pages 63 and 87 there is a multi-year capital project beginning in 2016 to eliminate the Jarvis DS. On Page 63 it indicates "*The transformer would be used as a replacement of a spare at another station*". Once the existing station transformer at Jarvis DS is no longer required then HCHI would be able to eliminate the current two spare transformers that are identified as end of life and maintain the former Jarvis DS transformer as a spare. This is also identified in Appendix H at section 7.3.1.3 bullet point B in the Distribution Asset Management Plan (2014-2034) on page 39 which indicates *"Jarvis DS Is scheduled for retirement in 2018 (See Distribution System Plan for details). This will provide HCHI with a Spare Distribution Substation transformer and allow us to retire the two existing spare 2 MVA transformers which exceed 60 years of age in 2018."*

b. Please explain why porcelain insulators have not been designated as an asset for which action is required to be taken on a high priority basis, given the concerns expressed in the Porcelain Arrestor Replacement Program Section 2.10 (p27)?

<u>HCHI Response</u>

The function of a porcelain insulator is different than the function of a porcelain lightning arrestor. Insulators are used to support and/or separate the conductor away from the pole and provide insulation between the conductor (at full line potential) and the mounting bracket (at zero potential).

HCHI is aware that other utilities have implemented programs to replace porcelain insulators, typically of the horizontal post type, due to failure of the bond between the metal base and porcelain due to cracking and water ingress. The failure mechanism is typically breakage which can cause the overhead conductors to come into contact with each other and cause an outage or to break free during work on the pole or adjacent poles. HCHI does typically replace horizontal post type porcelain insulators with a polymeric material on adjacent poles and directly on poles where work is being completed in order to ensure safety for staff. At this time, based on HCHI's experience of very few breakage failures of horizontal post type porcelain insulators, it has not implemented a formal porcelain insulator replacement program; however, this could become a maintenance program to be considered as part of its 2019 Cost of Service.

Porcelain lightning arrestors are designed to carry over voltage, typically a result of lightning strikes, through the device upon operation from the high voltage terminal to ground. Due to the poor seal in porcelain arrestors, which can allow moisture to enter the device, porcelain arrestors typically fail in an explosive manner. HCHI has experienced explosive porcelain lightning arrestor failure in urban areas; as such this program was identified as a new maintenance program beginning in 2013.

c. Figure 3-6 (page 65) suggests that a number of pole top transformers should be "flagged for action". Please explain the program for replacement of pole top transformers and show the distribution of the replacements for 2014 – 2018.

<u>HCHI Response</u>

The replacement program and HCHI's sustainment strategy for pole mounted transformers is described in Appendix H, Distribution Asset Management Plan Section 7.3.3 on Pages 40 and 41. The replacement of pole mounted transformers is on a run to failure strategy, as indicated in Appendix H of the Kinectrics prepared Asset Condition Assessment ("ACA") Study on page 60 "*Many utilities treat residential pole top transformers as run-to-failure assets*". It is not possible to show the distribution of replacements for 2014-2018 as the quantity of failures and subsequent replacement in each year is unknown. As indicated in Appendix H of the Distribution Asset Management Plan in section 7.3.3 on page 40 "*Over the next twenty (20) years it is estimated that eighty eight (88) in year one (1) to one hundred and fifteen (115) units in year twenty (20) will have to be replaced annually or a total of 1765 over the next twenty years*." HCHI's asset management strategy, however, is predicted by the Kinectrics ACA study which, as referenced on page 65, based on their analysis, HCHI may experience more or less failures in any given year than the study suggests. The current health index of HCHI's pole mounted transformer population is 92%.

1.2 Are the customer engagement activities undertaken by the applicant commensurate with the approvals requested in the application?

1.2 Staff 8. Evolution of Customer Engagement

Chapter 2 of the Filing Requirements states, "The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations." (Emphasis added)

a. Please describe the differences, if any, between customer engagement conducted in preparation for the current application and previous customer engagement.

HCHI Response

HCHI did not substantially change its customer engagement strategy in preparation for the current application.

b. Please explain how customer engagement has been enhanced.

HCHI Response

HCHI has an active communication strategy with its customers promoting ongoing business elements, accomplishments and changes in regulatory matters.

HCHI enhanced its communication strategy in 2012 and 2013 to include an updated website to improve messaging and information sharing, introduction of customer web portals to enhance their access to account information, implementation of a mobile application to better reach the change in customer habits, and the launch of Twitter to provide real time messaging. HCHI has a customer newsletter, *The Wire*, which is shared with customers electronically and a printed copy is included in their bills. A new bill insert, *Powered Up*, was also issued, and it specifically addresses HCHI's work in the community, including capital plans, student mentoring and community contributions.

As noted in its 2014 Cost of Service application, HCHI is adding new customer engagement elements to promote and entice feedback from its customers. HCHI has scheduled its first face-to-face customer session for April 10, 2014. This session will focus on HCHI's business elements, including work on the Regional Plan, Long Term Energy Plan as well as its specific Distribution System Plan.

c. If HCHI serves any reserves for First Nations communities, has HCHI reached out to engage this group specifically?

<u>HCHI Response</u>

HCHI does not serve any First Nations communities.

1.2 VECC 1.

Reference: E1/T2/S1

Has HCHI undertaken any consumer surveys in the past 4 years? If so please provide these.

HCHI Response

HCHI has not undertaken any consumer surveys in the past 4 years.

1.2 VECC 2.

Reference: E1/T2/S1

Does HCHI undertake transactional surveys (i.e. after engagement with a customer)? If so please provide a summary of these. If not, please explain why such surveys are not used.

HCHI Response

HCHI does not undertake formal transactional surveys. With complex transactions, HCHI does informally follow-up with customers. There is no formal tracking of these measures.

HCHI is considering implementing transactional surveys this summer as a pilot.

1.2 VECC 3.

Reference: E1/T2

Please explain how HCHI communicates the availability of LEAP assistance.

<u>HCHI Response</u>

HCHI informs customers on the LEAP program through multiple channels throughout the year, including:

- Each collection notice provides customers with standard information on the availability and how to apply and access the funds;
- Each customer calling in to make payment arrangements who exhibit difficulty are made aware of the LEAP and how to apply;
- HCHI's agency partner, the Dunnville Salvation Army and Family Services, promotes the LEAP to its customers;
- OEB *Take Charge* bill inserts; and
- HCHI's website.

1.2 VECC 4.

Reference: E1/T2/S1/pg.3

Does HCHI track and categorize customer enquiries and complaints? If so please provide a summary of the annual results for 2010 through 2013. If not please explain how HCHI gains an understanding of customer concerns.

<u>HCHI Response</u>

HCHI does not categorize enquires or complaints. HCHI tracks all enquires received and reported through SQR's. HCHI responds to all customer enquiries and complaints. Customer complaints are not categorized with the exception of enquiries that are formally given to HCHI via the Ontario Energy Board (the "OEB" or "Board").

A customer dispute can come by letter, email or over the phone. Each inquiry is responded to and investigated by the Department Supervisor and/or the Manager.

Customer Complaints deemed as unusual are discussed during weekly Managers meetings.

2 Performance Measures

2.1 Does the applicant's performance in the areas of: (1) delivering on Board-approved plans from its most recent cost of service decision; (2) reliability performance; (3) service quality, and (4) efficiency benchmarking, support the application?

2.1 Staff 9. Service Reliability Indices

Reference: ***Appendix F to Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 201 – Feeder Performance Indices***

HCHI has provided Service Reliability Indices ("SRI") by all circuits excluding loss of supply for 2011 – 2013.

a. For each of the years for which there are records, please describe the causes of the incidents:

i. Highest SAIDI

ii. Highest SAIFI

HCHI Response

Please note that HCHI has now discovered an error in the reporting for Service Reliability Indices by "All Circuits w/o Loss of Supply" for January 1 to December 31, 2011 with respect to how one significant outage was assigned to circuits. The number of customers and duration of the outage did not change. The error has been corrected and HCHI is taking this opportunity to submit a revised version to the previously submitted Appendix F to Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013 – Feeder Performance Indices, January 1 to December 31, 2011, in the following table.

Exhibit 2 – Appendix A – Consolidated Distribution Plan
Appendix F – Feeder Performance Indices
January 1 to December 31, 2011

January 1 to December 31 2011

Service Reliability Indices by All Circuits w/o Loss of Supply

Circuit	Total Cust Hours of Interruptions (1)	Total Cust Interruptions (2)	Total Number of Customers (3)	SAIDI Average Hours of Interruptions /Cust (4) = (1) / (3)	SAIFI Average # of Interruptions /Cust (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Argyle F1	45.00	30	165	0.272727	0.181818	1.500000
Argyle F2	1,862.59	250	247	7.540850	1.012146	7.450358
Canfield F1	9,484.31	2278	507	18.706726	4.493097	4.163437
Canfield F2	46.08	5	79	0.583291	0.063291	9.216018
Canfield F3	134.41	89	305	0.440689	0.291803	1.510228
Decewsville F2	215.25	254	551	0.390653	0.460980	0.847440
Decewsville F3	500.17	169	290	1.724724	0.582759	2.959584
Dunnville F1	414.42	99	570	0.727053	0.173684	4.186068
Jarvis F3	1,890.17	359	427	4.426628	0.840749	5.265101
Lythmore F3	31.67	56	180	0.175944	0.311111	0.565534
Selkirk F3	6,575.50	2594	1335	4.925468	1.943071	2.534888
Selkirk F4	5.60	8	460	0.012174	0.017391	0.700017
27M3	4.00	1	183	0.021858	0.005464	4.000366
27M4	65,397.74	27225	3378	19.359899	8.059503	2.402121
27M5	1,954.25	3733	3455	0.565630	1.080463	0.523507
27M6	1,257.44	1376	1272	0.988553	1.081761	0.913837
31M1 Dunnville	25,576.76	10734	5520	4.633471	1.944565	2.382780
31M2 Dunnville	19,277.92	6001	402	47.955025	14.927861	3.212451
57M3 Jarvis	1,356.36	308	165	8.220364	1.866667	4.403766
57M4 Jarvis	13,127.92	3047	2729	4.810524	1.116526	4.308475
57M5 Jarvis	4.00	2	5	0.800000	0.400000	2.000000
57M6 Jarvis	26,385.78	10819	3340	7.899934	3.239222	2.438837

2011 Canfield F1 (8 kV)

Highest SAIDI 18.706726; Highest SAIFI 4.493097

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	9	305	655.17
1	Scheduled Outage	0	0	0
2	Loss of Supply	0	0	0
3	Tree Contacts	5	408	2152.67
4	Lightning	3	3	11.96
5	DefectiveEquipment	1	4	14.67
6	Adverse Weather	5	142	403.5
7	Adverse Environment	0	0	0
8	Human Element	1	240	160
9	Foreign Interference	3	1176	6086.34

Code 9 - On February 7, 2011 a Dump Truck drove down Haldimand Highway 56 with the box elevated. The truck caused significant damage to our equipment including tearing down multiple span guys, service wires, neutral conductors and phase conductors at 12 separate locations along an approximate 4.8 km stretch where these crossed Highway 56. The truck also broke 11 Hydro poles which required immediate replacement in order to restore power to residents and businesses.

Code 3 - Two of the Tree Contact interruptions were off road lines which led to increased response and repair times and damaged conductors.

2011 31M2 (Hydro One Owned 27.6 kV Feeder)

Highest SAIDI 47.955025; Highest SAIFI 14.927861

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	2	424	523.5
1	Scheduled Outage	1	75	225
2	Loss of Supply	0	0	0
3	Tree Contacts	2	25	38.5
4	Lightning	1	1	3.5
5	DefectiveEquipment	4	207	1380.25
6	Adverse Weather	1	67	636.5
7	Adverse Environment	1	1	1.5
8	Human Element	0	0	0
9	Foreign Interference	2	5201	16469.17

The 31M2 is a Hydro One owned feeder.

Code 9 - On September 25, 2011 a car accident damaged HCHI equipment. The Dunnville M2 (Hydro One Circuit) was supplying the

Dunnville M1 (Haldimand County Hydro Circuit) at the time which increased the number of customers who experienced the interruption.

Code 5 – Overloaded Step Down transformer and recloser failures at location number SD-88 and R4890.

2012 Canfield F1 (8 kV)

Highest SAIDI 5.691654; Highest SAIFI 3.009615

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	2	2	3.25
1	Scheduled Outage	9	677	1694
2	Loss of Supply	0	0	0
3	Tree Contacts	0	0	0
4	Lightning	3	3	6
5	DefectiveEquipment	4	99	154.83
6	Adverse Weather	6	773	1079.58
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	1	11	22

2012 57M6 (27.6 kV) Jarvis

Highest SAIDI 5.060976

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	23	265	1111.84
1	Scheduled Outage	2	160	630
2	Loss of Supply	0	0	0
3	Tree Contacts	3	139	600.17
4	Lightning	10	287	804.58
5	DefectiveEquipment	9	151	583.65
6	Adverse Weather	15	6190	13033.67
7	Adverse Environment	1	54	108
8	Human Element	0	0	0
9	Foreign Interference	6	14	31.75

Code 6 – Adverse weather causing an off road phase conductor to break and required repairs..

<u>2012 57M4 (27.6 kV) Jarvis</u>

Highest SAIFI 2.229388

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	4	267	489.92
1	Scheduled Outage	12	335	1139.75
2	Loss of Supply	0	0	0
3	Tree Contacts	1	2700	2700
4	Lightning	1	1	1.83
5	DefectiveEquipment	7	406	1362.84
6	Adverse Weather	6	92	172.92
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	2	2283	1302.58

Code 5 – HCHI experienced multiple failures of elbows and a primary cable failure in the community of Townsend

<u>2013 Decewsville F2 (8 kV)</u>

Highest SAIDI 23.358151

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	1	8	6
1	Scheduled Outage	0	0	0
2	Loss of Supply	0	0	0
3	Tree Contacts	1	607	14264.5
4	Lightning	0	0	0
5	DefectiveEquipment	0	0	0
6	Adverse Weather	0	0	0
7	Adverse Environment	0	0	0
8	Human Element	1	1	1.33
9	Foreign Interference	0	0	0

Code 3 – July 19, 2013 storm caused tree to fall in an off road line section.

2013 Decewsville F3 (8 kV)

Highest SAIFI 1.28333

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	3	4	4.02
1	Scheduled Outage	1	100	300
2	Loss of Supply	0	0	0
3	Tree Contacts	1	35	87.5
4	Lightning	0	0	0
5	DefectiveEquipment	0	0	0
6	Adverse Weather	1	200	4300
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	2	46	45.48

Code 6 – July 19, 2013 storm caused conductors to break in off road pole location.

2013 57M3 Jarvis (27.6 kV)

Highest SAIDI 18.900361

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	2	7	18.08
1	Scheduled Outage	1	4	10
2	Loss of Supply	0	0	0
3	Tree Contacts	1	1	3.75
4	Lightning	2	299	3086.73
5	DefectiveEquipment	0	0	0
6	Adverse Weather	0	0	0
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	0	0	0

The 57M3 is a Hydro One owned Feeder

Code 4 – July 19, 2013 storm

<u>2013 57M6 Jarvis</u> (27.6 kV)

Highest SAIFI 3.341263

Code	Cause of Interruption	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	14	224	277.23
1	Scheduled Outage	4	792	477.91
2	Loss of Supply	0	0	0
3	Tree Contacts	3	167	346.17
4	Lightning	25	6541	42543.33
5	DefectiveEquipment	4	188	267.5
6	Adverse Weather	7	234	442.45
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	7	4073	7021.92

Code 9 – 15 of the 25 Interruptions are from the July 19, 2013 storm event

b. Describe work that is currently underway or was previously completed to remediate the situation of these worst performing circuits, and mitigate any future occurrences.

<u>HCHI Response</u>

Canfield F1 Feeder:

In the fourth quarter of 2011, HCHI initiated a multi-year capital project to improve reliability, power quality and green energy project connections. Details of this project can be found in Exhibit 2 – Appendix A, Appendix J page 59 (2011) and 87 (2012). Reliability has improved in 2013 as can be seen from the January 1 to September 30 2013 YTD Reliability Indices for the Canfield F1 8 kV feeder.

31M2 and 57M3 Feeders:

These feeders are HONI-owned lines, so there are minimal opportunities for HCHI to improve reliability directly.

For overloaded Step-down transformer SD-88 and R4890 an alternate supply was available and switching was done to offload the step down transformer after loading was reviewed. HCHI has developed a Capital Program to address step down transformers where the connected load exceeds 75% of the nameplate. Details can be found in Appendix A Distribution System Plan Pages 37 and 38.

57M6 Feeder:

In order to mitigate impacts from lightning, HCHI has adopted a minimum Basic Impulse Level (BIL) of 150,000 for equipment and all new capital projects are built to Utility Standards Forum ("USF") standards. HCHI installs lightning arrestors at all equipment installations and at the end of lines in keeping with best practices.

57M4 Feeder:

In 2011 and 2012, HCHI experienced multiple failures of underground distribution equipment (i.e. elbows and a primary cable fault) in the community of Townsend. Townsend was constructed as a radial underground system in 1979.

In 2011, a small overhead line extension was built to provide a loop to the existing underground residential portion of the community; however, the main three phase commercial and industrial customers, including a large senior's residence, were still on a radial underground system.

In 2012, HCHI initiated a capital project to extend a feeder from Jarvis to Townsend to provide a loop to the underground distribution system. Details of this project can be found in Appendix A, Appendix J, Page 85.

Once the loop feed was established to the residential area, and upon completion of the 2012 capital project, HCHI undertook significant maintenance activities in Townsend including re-terminating all cables and replacement of primary junction bars in underground vaults to improve reliability and also to improve safety for HCHI line crews.

Tree Contacts:

HCHI has an extensive and aggressive tree trimming program which is critical to minimizing outages due to tree contacts. The details of this tree trimming program can be found in Appendix A, Appendix H – Maintenance and Inspection Program, at page 6.

Off Road Lines:

HCHI's Distribution System Plan indicates "*A significant number of projects as part of the rebuild onto roadways will locate the distribution lines to more accessible locations away from treed areas, which can result in reduced tree trimming costs, labor and truck time when responding to emergency calls in these areas.*" (Distribution System Plan Page 6) and "*Relocate Primary and where possible, relocate secondary to roadways and laneways"* (Distribution System Plan Page 8)

c. What target has HCHI set for the service Reliability Indices?

<u>HCHI Response</u>

HCHI targets the OEB approved standard "within the range of three years historical performance" as reported to the OEB annually under its Reporting and Record Keeping Requirements ("RRR"), section 2.1.4, as provided in the table below.

SAIDI and SAIFI (excludes Loss of Supply)
Reliability Indices

"Annual" 3 Year Historical Performance	Total Customer Hours of Interruption	Total Customer Interruptions	Total Number of Customers	SAIDI Average Hours of Interruption / Customer	SAIFI Average # of Interruptions / Customer
2011	175,114	69,334	21,002	8.34	3.30
2012	46,926	24,670	21,110	2.22	1.17
2013	205,338	54,338	21,183	9.69	2.57
Average	**142,459**	**49,447**	**21,098**	**6.75**	**2.34**

d. How frequently are the SRIs monitored by the executive?

<u>HCHI Response</u>

System SAIDI, SAIFI, CAIDI and Outages by Cause SRIs are monitored monthly by the executive and reported to HCHI's Board of Directors at each regular board meeting, which typically occur monthly.

2.1 Staff 10. Service Quality Requirements

Reference: Exhibit 2 Tab 8 Schedule 1

Table 31 includes the Service Quality Requirements (SQR) for 2008 – 2012.

a. Please update the table for 2013.

<u>HCHI Response</u>

HCHI has updated the Service Quality Requirements ("SQRs") and Indices in Table 31 to include 2013 actual data.

Table 31
Service Quality Requirements – 2008 to 2013

Service Quality Indicator	2008	2009	2010	2011	2012	2013	OEB Standard
New Connections - Low Voltage	95.7%	96.7%	99.2%	97.0%	99.0%	94.3%	90.0%
New Connections - High Voltage	N/A	100.0%	N/A	N/A	N/A	N/A	90.0%
Appointment Scheduling	N/A	98.8%	98.1%	99.1%	99.6%	99.9%	90.0%
Appointments Met	98.2%	98.7%	98.3%	98.9%	99.7%	100.0%	90.0%
Rescheduling a Missed Appointment	N/A	92.3%	98.0%	96.7%	100.0%	100.0%	100.0%
Telephone Accessibility	88.6%	80.4%	88.8%	83.4%	85.5%	81.1%	65.0%
Telephone Call Abandon Rate	N/A	3.3%	2.3%	3.1%	2.5%	3.5%	10.0%
Written Responses to Enquiries	97.7%	95.0%	99.3%	98.4%	99.8%	99.7%	80.0%
Emergency Responses - Urban	93.1%	100.0%	95.0%	87.5%	93.3%	90.0%	80.0%
Emergency Responses - Rural	100.0%	93.8%	100.0%	96.6%	100.0%	97.3%	80.0%
Reconnection Standards	N/A	N/A	N/A	100.0%	100.0%	100.0%	85.0%

b. In the period 2009 – 2011, HCHI did not meet the 100% standard for rescheduling a missed appointment. However in 2012, HCHI performed at the 100% standard. If HCHI took corrective action, what was it?

<u>HCHI Response</u>

The missed appointments not recorded as rescheduled in the period 2009 to 2011 were on account of appointments scheduled to obtain meter reads. The missed appointments were not rescheduled as the actual meter reads were obtained at the time of the subsequent regular cycle read.

c. Has HCHI its own performance standards for any indicator that is greater than the OEB Standard?

HCHI Response

HCHI has not developed its own performance standards for any indicator that is greater than the OEB Standard.

d. Have any of the indicators been a subject of customer consultations, and if so, what was the outcome?

HCHI Response

No indicators have been the subject of customer consultations as HCHI has not developed its own performance standards.

e. How frequently are the SQR monitored by the executive?

HCHI Response

Telephone Accessibility, Telephone Call Abandon Rate, Number of New Connections - Low Voltage , and Emergency Response Urban & Rural SQRs are monitored monthly by the executive and reported to HCHI's Board of Directors at each regular board meeting, which typically occur monthly.

2.1 EP 1.

Reference: Most Recent Cost of Service Decision

a. Please provide a list of all Board-approved plans from the most recent cost of service decision.

<u>HCHI Response</u>

HCHI's most recent Cost of Service ("COS") Decision was EB-2009-0265. There were no prior Board-Approved plans with regards to a Distribution System Plan; however, capital and OM&A expenditures were previously approved in that proceeding for the 2010 Test year.

Refer to page 65 of 66 of Exhibit 2 – Appendix A (DS Plan)

> <u>"Year over year Plan vs. Actual variances for Total Expenditures</u>
>
> This is the first DS Plan that has been filed with the OEB as part of the 2014 COS Distribution Rate Application. In its 2010 COS Distribution Rate Application, the 2009 and 2010 planned capital expenditures were submitted as part of the rate application. Table 5–21 lists the planned and actual capital expenditures for years 2009 and 2010.

Table 5 – 21
2009 and 2010 Planned vs. Actual Capital Expenditures

	2009		2010	
	Planned	Actual	Planned	Actual
Construction Projects, Betterments, Line extensions	$3,143,085	$3,027,000	$2,394,121	$2,387,789
Total Capital Expenditures	$4,429,099	$4,191,000	$3,312,301	$3,228,000"

The Board's Decision & Order in HCHI's 2010 COS rate application did not have any other requests for HCHI and to the best of its knowledge, there are no Board-Approved plans.

b. Please provide the evidence references in the current application that illustrates that the distributor is delivering on these approved plans.

<u>HCHI Response</u>

See response in a.

2.1 EP 2.

Reference: Exhibit 4, Tab 1, Schedule 2

Table 1 shows that maintenance costs were more than $500,000 less in 2010 than the Board approved figure and that administrative and general were more than $80,000 lower in 2010 than Board approved. For each of these areas, please explain why the actual costs incurred were significantly lower in 2010 than approved by the Board. In particular, what functions that were forecast to be done were not done in 2010.

HCHI Response

The maintenance cost variance of $500,000 is spread across all of HCHI's cost categories of which approximately: (i) $256,000 is attributed to labour and truck; (ii) $67,000 is attributed to materials; and (iii) $177,000 is attributed to direct purchases and subcontract work. The majority of the direct purchases and subcontract variance is on account of the underspend in tree trimming in 2010. HCHI has a five year tree trimming cycle with variable costs in each year depending on the area of the County scheduled for that particular year. In 2010, the line contractor did not complete all anticipated clearing scheduled for that year. The underspend in materials and a portion of labour and truck is attributed to the minimal occurrence of adverse weather in 2010. HCHI now uses a 5-year average to determine truck and labour hour requirements for budgeting storm costs. Other items contributing to the variance are (i) a 3 month Lineperson vacancy; (ii) additional regular hours coded to recoverable work for numerous motor vehicle accidents; (iii) shift of labour and truck hours to capital projects versus OM&A; and (iv) new staff in the Line Supervisor and Operations Manager positions resulting in a learning curve to become familiar with the organization and its programs.

The Administrative and General variance from 2010 Actual to 2010 Board-Approved was all in relation to internal labour costs. During 2010, one of the Financial Analyst positions (formerly the Accountant position) was vacant due to a sick leave that commenced March 12, 2010 through to January 17, 2011. An individual from a temporary agency was utilized commencing in May 2010 to cover the sick leave resulting in approximately 50% of the variance with a decrease in labour costs of $41,600. An additional $48,600 contributing to the decrease in costs is associated with two Management positions, including the Operations Manager and the Engineering Manager, becoming vacant in 2010. One position was vacant from January 30, 2010 to April 26, 2010 and the other from August 27, 2010 to September 20, 2010. The two Managers that left were both at Job Rate and when the new candidates were hired at steps of the Job Rate, not reaching Job Rates until October 26, 2011 and March 20, 2012, respectively.

2.1 VECC 5.

Reference: E2/T8/S1/pg.2

Please explain the significant increase in SAIDI and SAIFI figures (excluding loss of supply) in 2011.

<u>HCHI Response</u>

HCHI experienced a challenging year in 2011 with significant weather related impacts resulting in a significant portion of the increase in SAIDI and SAIFI figures in 2011. Notable events are detailed below:

- Feb 7, 2011 – Foreign Interference, Dump Truck incident described in IR Staff # 9;
- March 23, 2011 – Adverse Weather - Freezing Rain;
- April 28, 2011 – Adverse Weather - A severe windstorm struck Haldimand County with winds in excess of 100 km/h which caused extensive damage to HCHI's distribution infrastructure with many mature trees falling onto distribution equipment. HCHI brought in crews from another local distribution company ("LDC") as well as contractors to assist with restoration;
- June 4 and 5, 2011 – Adverse Weather;
- July 18, 19, 21 and 22, 2011 – The following notice was placed on HCHI's website:

> "Notice to customers in the former townships of Oneida, Seneca, North Cayuga, Rainham, and the north half of Walpole, and extending into part of Canborough
>
> This Notice is intended to inform customers about power interruptions which occurred as follows:
>
> • Monday, July 18, 2011 – generally from 8:15 PM to 10:46 PM
>
> • Tuesday, July 19, 2011 – generally from 8:24 PM to 8:30 PM
>
> • Thursday, July 21, 2011 – generally from 7:00 PM to 10:00 PM, except Cayuga which ended at 12:55 AM on July 22
>
> These outages affected a feeder line which normally supplies about 3670 customers. Haldimand County Hydro line staff have repeatedly patrolled the lines and not found anything which could have caused these outages.
>
> At this time, the afternoon of July 26, 2011, we continue to investigate the

> cause of these outages and have involved our engineering consultants and Hydro One to determine if there is an issue with the relay settings for this feeder line at the Caledonia Transformer Station. These relays are intended to protect the line itself and customer equipment from damage in the event of faults which can and do occur. One issue which complicates the investigation is the fact that the problem is intermittent, having occurred each of these evenings but then disappeared allowing us to restore power. We have moved some customer load to an alternative feeder where this was possible and this should help if relay settings are the problem.
>
> We apologize for the inconvenience to our customers. Please be assured that we are working to identify the problem and the solution as quickly as possible."

The cause was determined to be feeder settings with the new D60 Relay and HCHI worked closely with Hydro One to resolve the matter;

- July 29, 2011 – Lightning Storm; and
- August 24, 2011 – Lightning Storm.

2.1 VECC 6.

Reference: E2/T8/S1/pgs.7-11

Please provide a breakdown of the service reliability performance metrics into the different category of reasons for the outage (excluding supply loss Code 2 outages). The table below provides an example format.

Description	2010 Totals	2011 Totals	2012 Totals	2013 Totals
Scheduled				
Supply Loss				
Tree Contact				
Lightning				
Def. Equip.(other than pole)				
Pole Failure				
Weather				
Animals, Vehicle				
Unknown				
Total				

<u>HCHI Response</u>

The reference provided by VECC as E2/T8/S1/pgs.7-11 does not appear to be correct. HCHI has reported service reliability performance metrics in E2/T8/S1/pg. 2 Table 32. HCHI has provided metrics using the OEB cause codes (including supply loss Code 2) and updated for 2013. Additional information on Outages by feeder is detailed in response to IR Staff # 9.

The following table provides the Number of Customer Interruptions and Number of Hours of Customer interruptions, similar to the new OEB RRR guidelines (EB-2010-0249).

Service Reliability Indices – By Outage Code

		2008		2009		2010		2011		2012		2013	
Code	Cause of Interruption	Number of Customer Interruptions	Number of Customer Hours of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
0	Other/Unknown	6968	16588.97	3777	3438.77	9636	13540.08	14048	42428.73	2021	4198.54	4711	8125.07
1	Scheduled Outage	6707	20326.58	9068	22854.9	3740	8003.36	2770	5311.5	2525	6033.36	2327	4686.08
2	Loss of Supply	1100	1682.42	4037	6551.67	11553	4665.84	12380	3991.47	10464	12779.99	17870	51927.68
3	Tree Contacts	5829	15561.95	1059	2324.47	793	1114.81	3781	10619.16	3293	4838.67	3582	12608.03
4	Lightning	9029	27132.05	6651	15134.32	1974	4035.99	8120	23110.47	563	1523.35	14017	89859.06
5	DefectiveEquipment	8798	21937.78	717	2807.15	4051	9882.76	11463	8755.25	5192	10421.32	611	1039.77
6	Adverse Weather	7273	29593.38	6940	35204.87	4128	20009.09	18934	55599.48	8048	17439.79	22537	79275.67
7	Adverse Environment	3	17.5	2	9	1	2.17	3	6.58	180	421.5	6	3.15
8	Human Element	1005	601.58	372	1026.33	0	0	240	160	0	0	1	1.33
9	Foreign Interference	7843	13965.97	238	296.1	709	1349.64	9975	29122.42	2849	2051.32	6544	9739.75
		54555	147408.18	32861	89647.58	36585	62603.74	81714	179105.06	35135	59707.84	72206	257265.59

3 Customer Focus

3.1 Are the applicant's proposed capital expenditures and operating expenses appropriately reflective of customer feedback and preferences?

3.1 Staff 11. Staffing Levels

Reference: Exhibit 4 Tab 1 Schedule 2

On page 8, HCHI application shows that by the end of 2014, it will have hired 6 FTEs since 2010, its last cost of service application.

a. **Please identify any improvements in services and outcomes the applicant's customers will experience in 2014 and during the subsequent IRM term as a result of increasing the FTE count.**

HCHI Response

Customer Service Staff (1 FTE):

In 2012 the newly created Sync Operator position was filled. The Sync Operator fulfills the role of managing the Advanced Metering Infrastructure ("AMI") data communications between all touch points within the LDC and its AMI partners. Having the Sync Operator role as an employed individual rather than outsourced provides various benefits to HCHI, such as ensuring the knowledge gained stays within the LDC and also allows for cross departmental utilization for various AMI data projects.

The improvements that the Sync Operator role has brought to customers is the ability to collect, manage and analyze information from one or more sources, such as the AMI, centralized Meter Data Management Repository (MDM/R), Customer Information System (CIS) and utility Operational Data Storage (ODS) to ensure the accuracy of time-of-use meter data for customers, including accurate billing.

Engineering Staff (2 FTEs):

A Distribution Engineer was hired during September 2012. This position was expected to replace the cost of consultants that were currently performing some of the engineering services. The impact to the operating expenses is expected to be neutral after several years of training and experience is obtained. The addition of this position mitigated extra costs from consultants due to the additional work as a result of the Transmission Connected generation projects that are occurring in Haldimand County. The additional position was required for several reasons, including:

a) To provide assistance in response to the provincial governments initiatives resulting from the *Green Energy and Green Economy Act, 2009* (the "GEA") to address specific needs with Distributed Generation ("DG") and Smart Grid planning and initiatives;

b) To provide assistance to continue to comply with Electrical Safety Authority Regulation 22/04 and Standards. The increase in DG projects and related connection work has also resulted in the development and approval of additional construction and material standards that require approvals. ESA Regulation 22/04 requires Construction Standards to be approved and stamped by an Ontario Licensed Professional Engineer. The Distribution Engineer is expected to stamp these new standards and to also maintain and modify existing standards where necessary. The majority of this work was previously contracted out to consulting engineers; and

c) To perform Distribution System Analysis and coordinate protection and control analysis. The increase in DG activity also requires more review and analysis of the distribution protection and control systems. More importantly, the coordination of fuses, reclosers and breaker settings at the transformer stations require periodic review and modifications. HONI requires the LDC to calculate and provide the protection settings for D60 relays for feeders that are owned by an LDC. Work in this area will be increased as normal day to day switching of loads between feeders will be more difficult and complicated. Scenarios where loads are switched for normal construction work and/or back up situations will have to be studied and new settings calculated. It is important to have this knowledge readily available and 'in-house'. This type of planned engineering work was previously being contracted out with limited success.

A Meter Technician was hired during November 2013. This position was created to replace a sub-contractor that was providing cable locating services and a sub-contractor that was providing Meter Technician services. The Meter Technicians are cross trained to complete metering services, cable locating and cable fault locating as well as other technical services as required. HCHI's service territory is very large, and by utilizing three technicians to perform metering and locating services, work can be dispatched more efficiently by eliminating truck rolls to the same locations in the County and the capability to perform multiple job functions in the same trip.

Finance Staff (1 FTE):

One of the 6 full-time equivalents ("FTEs") added since 2010 was a third Financial Analyst position. This position was added in 2010 (but not included in the 2010 COS rate application) to provide a more permanent solution to the temporary Accounting Co-op Student position that was included in the 2010 COS. The FTE adds a more experienced candidate in order for the Finance department to sustain its core functions and requests amidst the increasing financial and regulatory reporting requirements, not to mention the special / ad hoc assignments that arise on a weekly / monthly basis. Significant changes in operations resulted in additional accounting and reporting requirements required by the Finance department such as; the Smart Meter Initiative including the implementation of Time-of-Use Pricing, International Financial Reporting Standards, implementation of the Harmonized Sales Tax, and the GEA (settlements with Generators, reporting to Independent Electricity Systems Operator, reporting to the OEB).

Operations Staff (2 FTEs):

HCHI undertook an analysis of existing line crew staff as part of its 2012 budget process.

This analysis was part of a multi-year strategy to increase the number of Powerline Workers from its current allocation of 12 to 14. As indicated at Exhibit 4/ Tab 2/ Schedule 4 on page 6 "*By increasing the complement of internal staff, the demand and construction crews are able to complete their work in a timely manner and the work currently performed by the line contractor is able to be completed internally by HCHI's own line crews.*"

Haldimand County Hydro currently operates with a three crew structure as follows:

Crew 1 – Trouble/Service Crew: 2 Workers;

Crew 2 – Demand Work / New Service Crew: 4 Workers;

Crew 3 – Construction Crew: 6 Workers; and

Occasional Crew 4 – Maintenance Crew: 2 workers (typically one each taken from the Demand and Construction crews reducing their numbers to 3 and 5 respectively).

The maintenance crew is typically comprised of workers taken from the other crews, which reduces the capacity of those crews. As a result the Maintenance Crew only functions for a short period of time in the winter and spring. By increasing the complement of staff, HCHI can develop a full time Maintenance Crew and maintain its complement of staff on the other crews. The Maintenance Crew can also function as a secondary Trouble/Service Crew when the primary Crew 1 is unavailable, or be assigned the call if they are geographically closer, which can improve HCHI's response time.

The table below contains data showing a Comparison between HCHI's Powerline Worker complement and other utilities, to the extent that information is available and could be analyzed.

	Haldimand County Hydro	Waterloo North	Halton Hills	Norfolk	Brant County Power
Total Customers*	20971	51914	20790	18940	9667
Rural Service Area (sq km)*	1216	607	225	549	254
Urban Service Area (sq km)*	36	65	26	144	4
Total Service Area	1252	672	251	693	258
Overhead km of lIne*	1634	1059	859	660	282
U/G km of Line*	89	488	545	108	38
Total km of Line	1723	1547	1404	768	320
*From 2010 Yearbook of Electricity Distributors					
# of Powerline Workers (PW)**	12	32	11	13	8
Line Supervisors/Superintendant**	1	1	1	1	1
**Determined from Organizational charts in Cost of Service Applications					
The following indicates the rates of linemen compared to Customers, Service Area and km of line:					
# of Customers per PW FTE	1748	1622	1890	1457	1208
Sq. km of Service Area per PW FTE	104	21	23	53	32
km of line per PW FTE	144	48	128	59	40
The following indicates the Number of Power line workers Haldimand would have in order to achieve the same rates as shown above for each utility:					
Equiv. HCHI PW to Achieve Customer Ratio	N/A	13	11	14	17
Equiv. HCHI PW to achieve Service Area Ratio	N/A	60	55	23	39
Equiv. HCHI PW to achieve km of line Ratio	N/A	36	13	29	43

From this table it can be seen that HCHI maintains a large overhead distribution system in one of the largest municipal service territories in the province. The current complement of 12 Powerline Workers is the smallest complement of three of the four comparable utilities, many of which have much smaller service areas and smaller distribution systems. Halton Hills has one less Powerline Worker than HCHI; however, their service territory is 20% of the size of HCHI's and 39% of their system is underground. An underground system is less susceptible to damage from storms and vehicle collisions. HCHI crews spend a significant portion of their time travelling between job sites and responding to trouble calls, as a result a smaller proportion of the workday is spent on completing required operating, maintenance and capital construction tasks.

Increasing HCHI's complement to 14 Powerline Workers would bring it only to the average Powerline Worker per customer ratio of the other utilities in this analysis (One Powerline worker per 1544), all the while maintaining a larger system in a larger service area.

Additional staff would allow HCHI construction crews to complete a greater proportion of end of life pole replacements and smaller capital projects internally, reducing reliance on contracted line crews. It is expected that this work could be completed internally by HCHI crews if staffing resources were more consistently in place on the demand and construction crews to guarantee this work could be completed in a timely manner.

b. How has the applicant communicated these benefits to its customers, and how did customers respond? Please provide some examples, including any customer feedback. If no communications took place, please explain why not.

HCHI Response

HCHI has not communicated these benefits to its customers as it has not fully implemented its customer engagement activities.

3.1 EP 3.

Reference: Exhibit 1, Tab 2, Schedule 1

a. What customer feedback and/or preferences has BHI [*sic*] received through its customer engagement process?

HCHI Response

HCHI has not engaged with its customers formally regarding its proposed capital expenditures and operating expenses.

b. Please provide a list of the questions asked of customers with respect to the proposed capital expenditures and operating expenses.

HCHI Response

Refer to response in a.

3.1 VECC 7.

Reference: E4\T2\S9/pg.1

Please recalculate the LEAP contribution based on the 2014 proposed revenue requirement (before revenue offsets).

HCHI Response

The recalculated LEAP contribution is $16,815 detailed in the following table.

LEAP Contribution Calculation

2014 Service Revenue Requirement Updated with Interrogatory Responses	$ 13,748,515
	0.12%
LEAP Contribution	$ 16,498

4 Operational Effectiveness

4.1 Does the applicant's distribution system plan appropriately support continuous improvement in productivity, the attainment of system reliability and quality objectives, and the level of associated revenue requirement requested by the applicant?

4.1 Staff 12. Benchmarking

References: ***Third Generation Incentive Regulation Stretch Factor Updates for 2013, November 27, 2012 – Power Systems Engineering;***

Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, Issued on November 21, 2013 and as corrected on December 4, 2013;

Appendix 2-L

Appendix 2-L shows that he OM&A cost per customer is expected to rise from $303 per customer based on the board approved OM&A in 2010 to $350 per customer in the test year. While Board staff is aware that HCHI's stretch factor assignment demonstrates its relatively high level of cost performance among Ontario distributors that the Board has identified in its RRFE that continuous cost performance is a criterion of operational effectiveness.

a. **Please outline the outcomes and improvements to service that customers will receive as a result of these increases.**

<u>HCHI Response</u>

HCHI is extremely aware of the cost pressures its customers are facing. While its portion of the bill represents 28%, HCHI recognizes the importance of minimizing cost impacts to customers. As noted in the OEB's *2012 Yearbook of Electricity Distributors*, HCHI delivers electricity to the fourth largest service territory in the province with 97% classified as rural service area (1216/1252 sq. km.).

Board staff have identified HCHI's OM&A cost per customer increasing by $47. HCHI has completed a variance review of the increase using the materiality threshold, and with reference to Exhibit 4 / Tab 2 / Schedule 2 / Table 6 and Exhibit 4 / Tab 2 / Schedule 3. These references are used to guide the response below:

- Increased complement of FTE's contributes a variance of $17 per customer. The outcomes and improvements to service that customers will receive as a result of increases relating to new staff are described in the response to Staff IR # 11.
- HCHI's Embedded Distributor (HONI) contributes to a total variance of $9 per customer for HONI Sub-transmission charges. With the offsetting revenue attributable to these costs, there is no impact to HCHI's customers.
- The decrease in tree trimming costs contributes a negative variance of $(3) per customer. The decreased tree trimming costs do not stem from a reduction in tree trimming activity but rather reflect the impact of lump sum competitive bidding on reducing tree trimming costs. This trend could reverse based on market conditions and result in reductions or increases in the future. Customers benefit from levelized tree trimming cost recovery as applied for in the 2014 Test Year (see Exhibit 4 / Tab 2 / Schedule 3 on pages 1 and 2 for a description in the methodology).
- The increase in distribution transformer costs contributes a variance of $3 per customer. The additional repairs and maintenance being completed will improve reliability and service for customers.
- The increase in meter reading costs contributes to a variance of $4 per customer in meter reading. This is on account of the implementation of smart meters. The smart meter initiative and its associated benefits were a provincially mandated program.
- The increase in bad debt of $3 per customer does not contribute to an outcome or improvement in service.
- The increase in outside services contributes to a variance of $3 per customer. The cost increase is for IT system monthly monitoring, AMI security audit, costs associated with the new smart meter environment and the Harris Northstar Customer Information System ("CIS"). Customers benefit from a secure IT environment. Data security and cyber security and privacy is a new evaluation criterion in the Renewed

Regulatory Framework and Chapter 5 Filing Requirements. Improvements to the Harris Northstar CIS allow HCHI to better serve its customers as this tool is used daily by Customer Service staff to respond to customer inquiries and billing.

The items discussed above comprise the material items that contribute to the increase in per customer OM&A costs from 2010 Board Approved to 2014 Test Year.

b. Please identify any customer engagement that supports the further increases proposed in this application.

<u>HCHI Response</u>

HCHI is not anticipating additional customer engagement costs. Alternatively, HCHI will be reallocating costs where it traditionally has had opportunities to engage with its customers, including focus groups, online surveys, CDM community events, school safety programs, and increased community speaking engagements.

c. Please provide details on any initiatives undertaken to reduce the rate of increase in cost per customer.

<u>HCHI Response</u>

HCHI utilizes all opportunities to examine costs and, wherever possible, implement cost efficiencies.

HCHI has listed a number of Cost Savings opportunities in page 5 and 6 of the DS Plan. These are copied below:

<u>“Sources of Cost Savings</u>

Capital expenditures over the forecast period are expected to result in improved reliability, power quality, efficiency through reduced costs and reduced losses. Improved reliability and power quality result in a reduction of after hour trouble calls in response to outages and translates into reduced costs. New capital construction projects involve new lines on higher poles, located in more accessible areas onto public right of ways, away from trees, especially projects along the Lake Erie shoreline. This also results in reduced O & M tree trimming costs and improved efficiency from improved roadway accessibility on an ongoing basis. A reduction in line losses is theoretically accomplished due to the nature of new construction to current standards, larger conductor and more efficient transformers. A reduction in losses does occur but is difficult to quantify in terms of the Total Loss Factor considering HCHI's large service area, customer density and large quantities of lines. HCHI is expecting that the reduction of Total Loss Factor below the provincial target of 5% to be a long term initiativeCost savings have been achieved through the lump sum construction tender process of several capital construction projects in 2012 and 2013. It is expected that this will continue for projects in 2014 and future years. Experience thus far has resulted in cost savings and cost certainty prior to starting construction. Cost savings are also expected to be achieved through integration of software systems that contain asset data. Also in 2013, a tender has been issued to firms for detailed designs and cost estimates for some of the 2014 Capital projects. The intent of tendering a year in advance is to have detailed designs and detailed cost estimates completed the year prior to construction. The projects can be tendered at the start of the year with the expectation of competitive pricing and cost certainty. This also allows for projects to be staggered throughout the year to balance resources. Historically, HCHI has been estimating projects for approval based on preliminary design. Then design and construction of various projects occur at the same time. We hope to achieve more cost certainty and savings by doing detailed design in advance of project approval, lessening the risk of cost overruns and unforeseen circumstances that were not taken into account during project estimating. Further savings are anticipated through material purchases. The completion of detailed design for all projects at the start of a year includes completed material lists for these projects. The material lists for all projects can be combined for volume price discounts when ordering materials.

The CE Plan consists of a number of System Service type projects involving conversion of lines from 4.8/8.32 kV to 16/27.6 kV. These projects all have the same goals in improving reliability, power quality and reducing losses through transformation and line losses. The construction of these lines to current standards improves safety, improves reliability, reduces trouble calls, and reduces line losses. A significant number of projects as part of the rebuild onto roadways will locate the distribution lines to more accessible locations away from treed areas, which can result in reduced tree trimming costs, labor and truck time when responding to emergency calls in these areas.

<u>Cost Savings through efficiency</u>

Investments in an Automated Meter Infrastructure (AMI) system, as part of the provincial smart meter initiative to have smart meters in every Ontario home by December 31, 2010 has provided HCHI with hourly meter data at each end point that was previously not available. The hourly data has been aggregated to a transformer and/or upstream Step-Down ("SD") transformer to determine maximum loading over a period of time. A number of instances have been determined where SD transformers have been significantly overloaded causing mechanical damage and premature failure. This data has been valuable in assisting engineering staff to prioritize the worst case scenarios first. The data has also identified areas where available capacity for load is limited and has been a driver for upgrade projects. The SD transformer load study is discussed in more detail in Section 5.3.2.

As part of HCHI's information management process, HCHI has integrated the Geographical Information System (GIS) to the CYME Distribution Analysis software. We anticipate that feeder optimization studies and analysis will identify other opportunities for projects that will reduce losses and optimize the operation of the distribution system. Opportunities to integrate the GIS to the Operational Data Store (ODS) would allow for utilization of hourly data for further analysis in CYME. This integration has yet to be explored.

Increased access to real time outage information from the AMI system is in progress. This information will certainly aid in outage notifications, response planning, and restoration efforts resulting in reduced O & M costs related to power outage events. Reporting, trending and analysis of these events will also be enhanced.

Investments in additional meter points throughout the distribution system along with totalization of meters will enable staff to assess sections of line or feeders that may have a greater contribution to losses. This is also important for theft detection.

The opportunity for undetected theft on private property is greater now that meter reading staff do not visit properties on a month to month basis to obtain a meter reading. Utilization of this data is critical in protecting assets and energy theft.

In August 2009, Kinectrics prepared a report entitled "Distribution Loss Assessment at Haldimand County Hydro Inc. ("Distribution Loss Assessment Report") Kinectrics Report No. K-418006-001-GE-0001 dated August 10, 2009 (attached as Appendix L) and the report discusses a 'bottom up' modeling approach to determine losses. Using the hourly meter data in conjunction with the analysis software, we believe that these sources of losses will be more readily identified."

Elimination of Banner Installation

In 2011, HCHI advised Haldimand County that, effective January 2012, it would no longer install banners and as such no banner amount was budgeted for 2012 and 2013. This change allows HCHI to utilize its linemen and equipment where they are most needed, resulting in operational efficiency and improvement by the elimination of this program in 2012. See also response to EP IR # 10 c.

Ontario One-Call

The onset of the provincially legislated "One-Call" in 2013 increased locate requests in the order of 90%. HCHI previously utilized external services to perform underground locates. At the end of 2013, a new Meter Technician was hired, reducing annual budgeted costs in the order of $75,850 in 2014. HCHI is using the ESRI GIS system to attempt to resolve locate requests prior to dispatching field personnel. This has been effective in managing the increased volumes and approximately 18% of locates are now cleared without dispatching field personnel.

Tree Trimming Lump Sum Area Clearing

Prior to 2011, HCHI hired tree trimming contractors for area clearing on a labour and truck hourly basis. In 2011, HCHI implemented Lump Sum Tendering of these areas and has seen a reduction in costs to trim these areas.

HCHI has demonstrated continuous cost improvements with five year tree trimming reducing in the order of $81,000 from the 2010 Board Approved to the 2014 Test year without compromising effectiveness. Cost improvements were achieved through a combination of continued cycle trimming strategy as well a competitive market. It is recognized that the market may adversely impact (i.e. increase) costs in the future.

Tree Trimming Hold Off Credit Program

During 2013, HCHI implemented a "Tree Trimming Hold-Off Credit". HCHI recognizes that there are operational efficiencies to allowing trained and qualified tree trimming crews to set and surrender their own hold offs on the 8 kV hydraulic reclosers as they are already in the area where the hold off needs to be set. Prior to the implementation of this program, HCHI would need to send a line truck to set and surrender hold offs on a daily basis for contracted tree trimming crews which could be in a different area than their other work for the day. When HCHI implemented lump sum area clearing contracts HCHI was at risk for contractor delay claims if hold offs were not set by the times stipulated in the contracts and this risk was mitigated by allowing the contractor to set and surrender hold offs to their schedule. HCHI has estimated efficiency improvement in the order of $6,000 in 2013.

Ground Level Repairs

As required by the DSC, HCHI is required to inspect the distribution plant at regular intervals. HCHI's tender is unique in that it also requests the inspector to complete "Ground Level Repairs" and it has been HCHI's experience that these repairs can be effectively corrected during the inspection process.

By having the inspector complete ground level repairs at the same time as the inspection, HCHI has achieved efficiency savings by (i) not dispatching a second repair crew; (ii) maintaining the ground level distribution system in a good state of repair; and (iii) ensuring all safety and warning signs are installed and maintained on a regular basis. It is estimated that this program has mitigated costs of $250 dollars per day for each day that ground level repairs are completed based on a theoretical two hour round trip for a Lead Hand and a Journeyman in a pickup truck to complete these repairs. This program has allowed HCHI to redirect staff to complete other work.

Implementation of Autodialer

Up until August 2013, HCHI issued Past Due notices prior to commencing with the mandated connection/disconnection notification process. Since their inception, Past Due notices have not proven to lower the total number of disconnections. It is more efficient and cost-effective to use an automated phone call system to replace the issuing of Past Due notices, including savings on postage, paper and envelopes.

The elimination of approximately 19,000 Past Due notices is a component of the 2014 Operating Budget, with an estimated cost savings in the order of $15,000.

d. Please provide details on initiatives to improve the applicant's assignment for IRM stretch factors in future years.

<u>HCHI Response</u>

HCHI will continue to examine all operating costs as part of its normal business strategies, including:

- Reduction of costs to produce and mail customer's bill through promotion of e-Billing.

- Streamline activities and decision making where possible to bring forward solutions through data integration.
- Examine cost sharing opportunities with other LDCs where feasible.

4.1 Staff 13. Continuous Improvement

Reference: ***Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, p43 of 66 – Distribution System Maintenance and Inspection Program***

HCHI states in the second paragraph that that "the strategy behind the program was based on the fact that for the most part minimal maintenance had been performed or documented for the majority of distribution assets." In so doing HCHI developed the Distribution System Maintenance and Inspection Program in 2006, and updated it in 2013.

a. Please provide any statistics that indicate continuous improvement by HCHI.

HCHI Response

The 2013 Asset Condition Assessment at Appendix H on page 31 indicates Conclusion and Recommendation Number 2 "*Of the asset categories assessed, substation vacuum circuit breakers, pad-mounted transformers, step-down transformers, wood poles, concrete poles, metal poles, pad-mounted switchgear, underground XLPE cable s(both in duct and non-duct types), overhead reclosers and primary metering units were found generally to be in good shape with over 75% of the population in "very good" condition."*

Below is "Table 2 Summary of Health Index Distribution Changes" which compares the 2009 Asset Condition Assessment and the 2013 Asset Condition Assessment, both completed by Kinectrics.

Table 2 Summary of Health Index Distribution Changes

	Asset	Year	Very Poor		Poor		Fair		Good		Very Good	
			% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change
1	Distribution Station Transformers	2009	0.0%	12.5%	0.0%	12.5%	45.5%	-20.5%	45.5%	-20.5%	9.1%	15.9%
		2013	12.5%		12.5%		25.0%		25.0%		25.0%	
2	Circuit Breakers	2009	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
		2013	0.0%		0.0%		0.0%		0.0%		100.0%	
3	Pole Mounted Transformers	2009	8.4%	-6.7%	24.0%	-21.8%	8.5%	-6.1%	0.1%	6.1%	58.9%	28.5%
		2013	1.7%		2.3%		2.4%		6.2%		87.4%	
4	Pad Mounted Transformers	2009	0.0%	0.0%	2.4%	-2.4%	4.8%	-4.6%	6.9%	-6.9%	85.9%	13.9%
		2013	0.0%		0.0%		0.2%		0.0%		99.8%	
5	Vault Room Transformers	2009	0.0%	-	0.0%	-	100.0%	-	0.0%	-	0.0%	-
		2013	-		-		-		-		-	
6	Step-Down Transformers	2009	-	-	-	-	-	-	-	-	-	-
		2013	0.0%		2.8%		10.4%		10.4%		76.4%	
7	Poles	2009	3.7%	-3.5%	8.2%	-6.5%	25.0%	-19.9%	45.5%	-17.4%	17.6%	47.3%
		2013	0.1%		1.7%		5.2%		28.1%		64.8%	
8	Gang Operated Overhead Switches	2009	0.0%	0.0%	22.2%	-22.2%	0.0%	6.5%	16.7%	-16.7%	61.1%	32.4%
		2013	0.0%		0.0%		6.5%		0.0%		93.5%	
9	Pad Mounted Switchgear	2009	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	71.4%	-71.4%	28.6%	71.4%
		2013	0.0%		0.0%		0.0%		0.0%		100.0%	
10	Underground XLPE Cable (segment)	2009	0.0%	-	2.7%	-	0.0%	-	21.8%	-	75.4%	-
		2013	-		-		-		-		-	
11	Underground XLPE Cables (in Duct, km)	209	-	-	-	-	-	-	-	-	-	-
		2013	0.7%		6.3%		0.0%		0.0%		93.0%	
12	Underground XLPE Cables (Non-Duct, km)	2009	-	-	-	-	-	-	-	-	-	-
		2013	14.5%		0.0%		0.0%		2.8%		82.7%	
13	Overhead Reclosers	2009	0.0%	0.0%	60.0%	-60.0%	0.0%	0.0%	0.0%	0.0%	40.0%	60.0%
		2013	0.0%		0.0%		0.0%		0.0%		100.0%	
14	Primary Metering Units	2009	0.0%	4.8%	0.0%	0.0%	0.0%	0.0%	6.3%	-6.3%	93.8%	1.5%
		2013	4.8%		0.0%		0.0%		0.0%		95.2%	

Below is a graphical representation of Table 2:

The Health index of Asset Category Distribution Station transformers without the spare station transformers is discussed in response to Staff IR # 7. The two spare distribution station transformers were not included in the 2009 Asset Condition Assessment but were included in the 2013. Improvements have been made to the Health Index of pole and pad mounted transformers, poles of all types, gang operated overhead switches, pad-mounted switchgear and overhead reclosers. Overall the above graph suggests to HCHI that the "health" of the assets has improved since 2009.

b. Has HCHI considered industry specific benchmarks in setting operating and maintenance budgets?

HCHI Response

HCHI has not considered industry specific benchmarks in setting operating and maintenance budgets.

c. If the answer to b. is yes, please provide any trends in HCHI's performance.

HCHI Response

Not applicable.

d. HCHI has indicated that it has advanced timing of the engineering design work and consolidating purchasing as sustainable improvement. Has HCHI found or is it planning other measurable and proven improvements for asset management and OM&A?

HCHI Response

HCHI continues to explore integration of software systems that contain asset data to improve Asset Management and OM&A – refer to DS Plan, page 5. HCHI is investigating providing real time outage mapping to on-call staff using the Operational Data Store (ODS) which leverages smart meter alarms and a web portal so that on-call staff can view significant outage events in real time to accelerate response and restoration times.

HCHI has also leveraged its AMI system to determine maximum loading over a period of time for Step Down Transformers – refer to DS Plan, page 6.

The AMI is also being used to determine maximum loading of transformers when new customers are requesting connections to determine if an increase in capacity is required upstream of the customer.

4.1 EP 4.

Reference: Exhibit 1, Tab 1, Schedule 1

a. What was the stretch factor applicable to HCHI in each of 2011, 2012 and 2013?

<u>HCHI Response</u>

The stretch factors applicable to HCHI are as follows:

2011 – 0.40%

2012 – 0.40%

2013 – 0.40%

b. What stretch factor has been assigned to HCHI for 2014 based on the final PEG report?

<u>HCHI Response</u>

The stretch factor assigned to HCHI for 2014, based on the final PEG report, is 0.15%.

4.1 VECC 8.

Reference: E2/T5/S3/pg.2

Please explain what metrics (reliability targets etc.) or other objectives that HCHI is using to assess the success of its Distribution System Plan. Specifically, please discuss the separate metrics used to judge, (1) the success of the plan itself (e.g. in achieving any stated goals) and, (2) the success of the plan's implementation.

<u>HCHI Response</u>

See response to Staff IR # 5 d.

4.2 Are the applicant's proposed OM&A expenses clearly driven by appropriate objectives, and do they show continuous improvement in cost performance?

4.2 Staff 14. Cost Performance

Reference: Exhibit 2 Appendix "A" "; Consolidated Distribution Plan, November 4:

- ***Appendix J: Capital Expenditures Historical Years***
- ***Appendix K: Capital Expenditures Forecast Years***

Historically and on a forecast basis, HCHI installs buried plant. While Board staff understands the impact on reliability, it is also cognizant of the greater installation costs for underground installations vs. overhead.

a. What is HCHI's policy guideline regarding the installation of underground systems?

HCHI Response

Underground systems are installed with the development of new residential subdivision projects. HCHI provides the developer its underground distribution system guidelines and approved materials.

Projects that involve converting from overhead to underground are reviewed on an individual basis. They are considered when Haldimand County is planning civil infrastructure projects (i.e. new water, sewer mains, water services and road reconstruction). This is the opportune time to install duct as there is cost sharing in the trench construction. There are significant savings for the utilities in restoration costs for sidewalks, curbs and landscaping as these costs would be incurred with the original municipal projects.

Underground installations are also considered along the Lake Erie Shoreline, as a last option, where an underground option is the only alternative because of narrow right-of-ways and proximity to homes.

b. What cost / benefit analysis is conducted to assist in underground/overhead decisions?

HCHI Response

A cost/benefit analysis is not performed, however options are considered. An overhead option is the first choice unless there are technical reasons such as those described in the response to a. above. Cost savings when participating with other utilities and the municipality on civil infrastructure projects in roadways is necessary to assist in making these decisions.

c. Are any costs (customer's or HCHI's) related to reliability used in the decision process? If so what are they and how were they determined?

HCHI Response

HCHI has not quantified costs related to reliability for these purposes.

d. Has HCHI undertaken any customer engagements or studies to understand how customers value service reliability (including both frequency and duration of outages) relative to cost on projects where underground vs. overhead options were being considered?

HCHI Response

HCHI has not undertaken customer engagements or studies for these types of projects. HCHI has participated in a public information meeting with the municipality regarding an overhead to underground project in an urban area and the customer feedback was positive.

4.2 Staff 15. OM&A Outcomes

Reference: Exhibit 4

HCHI has aligned and explained its OM&A along traditional grounds by explaining why the expenses are necessary from an operational point of view. Board staff is interested in the outcomes of these expenditures. Please describe programmes or items and their related costs and benefits which are included to enhance customer engagement, improve customer service and provide continuous innovation and cost improvement.

<u>HCHI Response</u>

Refer also to Staff IR # 12 c. for a description of programs that provide continuous innovation and cost improvement. Where cost avoidance or savings are known, they are described.

Refer also to Staff IR # 11 for a description of how each new staff position provides improved customer service. Refer also to Staff IR # 8 and Exhibit 1 / Tab 2 / Schedule 1 for a description of how HCHI intends to enhance customer engagement in the future.

HCHI recognizes that the new Chapter 5 Filing Requirements are a performance based approach which focuses on outcomes. It is HCHI's plan to work towards developing costs and benefits, where possible, to evaluate on a program or item basis going forward. Future evaluations of programmes or items will include metrics such as responding to customer preference including enhanced customer engagement, improving customer service and providing continuous innovation and cost improvement At this time HCHI has not completed a performance based review on the majority of existing programs and items.

HCHI has completed a number of business case reviews to determine how to proceed with certain programs or items and presents these to HCHI's Board of Directors for approval. These reviews include such items as the evaluation of additional metering staff and the new Sync Operator position versus continued contracting out (refer to Staff IR # 11) and implementation of the Autodialer (refer to Staff IR # 12 c.).

4.2 Staff 16. Billing Frequencies

Reference Exhibit 4

Board staff is interested in the current and any planned changes to billing frequencies

a. Please identify the billing frequency that the applicant is planning on using for the test period and beyond.

HCHI Response

HCHI currently bills its customers on a monthly basis (Exhibit 4 / Tab 2 / Schedule 1 / Page 7) and has no plans to change this billing frequency.

b. If the applicant is planning to implement monthly billing, please refer to parts c) through g) below. If not, please explain why not.

HCHI Response

See response to Staff IR # 16 a.

c. Please identify any impacts that the implementation of monthly billing has had on billing and collection expenses or any other OM&A category.

HCHI Response

Not applicable based on response to a. and b.

d. Please identify the percentage of customers on e-billing as of December 31, 2013.

HCHI Response

HCHI has 1.7% of its 21,288 customers on e-Billing as of December 31, 2013.

e. Please describe the Applicant's efforts to promote e-billing to its customers.

HCHI Response

HCHI has promoted e-Billing to its customers through various customer communication efforts such as on-bill messaging, bill inserts, through its website and Twitter. HCHI also ran a promotional contest where customers that registered for e-Billing qualified to be entered into a draw for an energy cost savings prize.

f. Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

HCHI Response

As previously mentioned, HCHI already bills monthly. Therefore there are no anticipated cost reductions.

g. As part of the decision making process, has the applicant determined the impact of the change to monthly billing on its working capital? If so, how is the working capital impacted by this change? If not, why not?

HCHI Response

Not applicable – see response to a.

4.2 Staff 17. Staffing Levels

Reference: Appendix 2-K

The applicant has proposed an 11% increase in headcount and 26% in employee compensation for the Test year relative to the 2012 actual levels.

a. What objectives has the applicant established for its operations?

HCHI Response

HCHI cannot confirm the percentages provided in Staff IR # 17. HCHI has calculated the percentages to be a 3% increase in headcount and a 16% increase in employee compensation for the 2014 Test Year relative to the 2012 actual levels.

HCHI has many objectives for its operations and some of the main objectives are detailed below:

- Compliance with conditions of its Distribution Licence;
- OEB Guidelines on SQRs and SQIs;
- Responsiveness to all stakeholders (i.e. Customer, Shareholder, Regulator, ESA, Government);
- Maintain distribution plant in a good state of repair; and
- Comply with obligations under GEA.

b. Please provide specific information on why the proposed cost increases are necessary for the applicant to achieve the objectives that the applicant has targeted in the capital and operating expenditure sections of its application, and the alternative methods for achieving these objectives that were considered and rejected in favour of the proposed headcount and compensation increases.

HCHI Response

As described in response to Staff IR # 11, an alternative method to an increased headcount is the use of consultants and contract staff to perform the services. The knowledge that is obtained by contractors or consultants is not retained by current staff and is not retained at HCHI. This knowledge and experience is not contained ‘in house’ and use for future purposes. Some of the additional positions that were added are expected to be OM&A neutral and generate future OM&A savings – refer to Staff IR # 11 a. for further details.

Refer also to Exhibit 4 / Tab 2 / Schedule 2 / Pages 7 and 8 which states "*Since 2010 HCHI has made an investment in people to address: (i) the significant regulated changes that have occurred in the electricity industry over the past four years, including the implementation of Smart Meters, time of Use Pricing, mandated CDM programs, and requirements under the GEA*".

The increase in costs in staffing is necessary to simply maintain HCHI's current objectives given the increasing volume of work including:

- HCHI has experienced a significant increase in "Recoverable" work, commencing in 2010 and continuing to date, which requires internal resources be partially diverted from HCHI OM&A to complete work required and reimbursed by third parties.
- Enhanced regulatory reporting;
- Additional government mandated obligations as outlined in response to EP IR # 9;
- Development and monitoring of the DS Plan;
- Connection of Renewable Energy Projects which is anticipated to continue until 2021 based on the Provincial Long Term Energy Plan;
- Reconstruction of HCHI's distribution plant to allow Transmission connected Renewable Energy Projects and their circuits to co-exist on the right-of-way;
- Significant utility plant relocations relating to capital projects from road authorities (i.e. the MTO and Haldimand County); and
- Extensive planning, customer notifications and switching for short term load transfers and outages to permit HONI to complete capital work at their transformer stations that supply HCHI.

4.2 EP 5.

Reference: Exhibit 4, Tab 1, Schedule 2

Please update Tables 1, 2 & 3 to reflect actual data for 2013. If actual data for all of 2013 is not yet available, please provide the most recent year-to-date actual figures that are available for 2013 in the same level of detail as shown in Table 3, along with the figures for the corresponding period in 2012. In doing so, please only include in 2012 the smart meter disposition costs actual incurred in 2012.

<u>HCHI Response</u>

HCHI has updated Tables 1, 2, and 3 to reflect 2013 actual data (internally prepared and unaudited) in the following tables:

Table 1
Summary of OM&A Expenses

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Test Year Interrogatory Responses
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operating	$ 1,418,231	$ 1,454,866	$ 1,669,077	$ 2,061,484	$ 1,715,783	$ 1,934,858
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,112,517	$ 2,751,043
SubTotal	$ 4,111,723	$ 3,642,500	$ 4,128,598	$ 4,373,098	$ 3,828,300	$ 4,685,901
%Change (year over year)			13.3%	5.9%	(12.5%)	22.4%
%Change (Test Year vs Last Rebasing Year - Actual)						28.6%
Billing and Collecting	$ 1,319,423	$ 1,305,988	$ 1,154,952	$ 1,867,865	$ 1,403,650	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 45,426	$ 143,208	$ 69,414	$ 69,320
Administrative and General	$ 1,967,377	$ 1,883,392	$ 2,029,380	$ 2,037,455	$ 2,162,735	$ 2,242,920
SubTotal	$ 3,333,636	$ 3,232,023	$ 3,229,758	$ 4,048,528	$ 3,635,799	$ 3,931,174
%Change (year over year)			(0.1%)	25.4%	(10.2%)	8.1%
%Change (Test Year vs Last Rebasing Year - Actual)						21.6%
Total	$ 7,445,359	$ 6,874,523	$ 7,358,356	$ 8,421,626	$ 7,464,099	$ 8,617,075
%Change (year over year)			7.0%	14.4%	(11.4%)	15.4%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Test Year Interrogatory Responses
Operating	$ 1,418,231	$ 1,454,866	$ 1,669,077	$ 2,061,484	$ 1,715,783	$ 1,934,858
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,112,517	$ 2,751,043
Billing and Collecting	$ 1,319,423	$ 1,305,988	$ 1,154,952	$ 1,867,865	$ 1,403,650	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 45,426	$ 143,208	$ 69,414	$ 69,320
Administrative and General	$ 1,967,377	$ 1,883,392	$ 2,029,380	$ 2,037,455	$ 2,162,735	$ 2,242,920
Total	$ 7,445,359	$ 6,874,523	$ 7,358,356	$ 8,421,626	$ 7,464,099	$ 8,617,075
%Change (year over year)			7.0%	14.4%	(11.4%)	15.4%

Table 2
OM&A Cost per Customer and FTE

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Test Year Interrogatory Responses
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	24,594	24,666	24,670	24,709	24,792	24,845
Total Recoverable OM&A	$ 7,445,359	$ 6,874,523	$ 7,358,356	$ 8,421,626	$ 7,464,099	$ 8,617,075
OM&A cost per customer	$ 302.73	$ 278.70	$ 298.27	$ 340.83	$ 301.07	$ 346.83
Number of FTEs	46	47	47	50	51	52
Customers/FTEs	535	525	525	494	486	478
OM&A Cost per FTE	$ 161,855.63	$ 146,266.45	$ 156,560.77	$ 168,432.52	$ 146,354.88	$ 165,712.98

Table 3
Summary of OM&A Expenses
(Excluding Smart Meter Costs)

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Test Year Interrogatory Responses
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operating	$ 1,418,231	$ 1,454,866	$ 1,669,077	$ 2,061,484	$ 1,715,783	$ 1,934,858
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,112,517	$ 2,751,043
Smart Meter Disposition Reallocation		$ 11,929	$ 78,655	$ (90,584)		
SubTotal	$ 4,111,723	$ 3,654,429	$ 4,207,253	$ 4,282,514	$ 3,828,300	$ 4,685,901
%Change (year over year)			15.1%	1.8%	(10.6%)	22.4%
%Change (Test Year vs Last Rebasing Year - Actual)						28.2%
Billing and Collecting	$ 1,319,423	$ 1,305,988	$ 1,154,952	$ 1,867,865	$ 1,403,650	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 45,426	$ 143,208	$ 69,414	$ 69,320
Administrative and General	$ 1,967,377	$ 1,883,392	$ 2,029,380	$ 2,037,455	$ 2,162,735	$ 2,242,920
Smart Meter Disposition Reallocation		$ 218,494	$ 265,498	$ (483,992)		
SubTotal	$ 3,333,636	$ 3,450,517	$ 3,495,256	$ 3,564,536	$ 3,635,799	$ 3,931,174
%Change (year over year)			1.3%	2.0%	2.0%	8.1%
%Change (Test Year vs Last Rebasing Year - Actual)						13.9%
Total	$ 7,445,359	$ 7,104,946	$ 7,702,509	$ 7,847,050	$ 7,464,099	$ 8,617,075
%Change (year over year)			8.4%	1.9%	(4.9%)	15.4%
	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Test Year Interrogatory Responses
Operating	$ 1,418,231	$ 1,466,795	$ 1,747,732	$ 1,970,900	$ 1,715,783	$ 1,934,858
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,112,517	$ 2,751,043
Billing and Collecting	$ 1,319,423	$ 1,512,741	$ 1,353,101	$ 1,462,963	$ 1,403,650	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 95,290	$ 93,344	$ 69,414	$ 69,320
Administrative and General	$ 1,967,377	$ 1,895,133	$ 2,046,865	$ 2,008,229	$ 2,162,735	$ 2,242,920
Total	$ 7,445,359	$ 7,104,946	$ 7,702,509	$ 7,847,050	$ 7,464,099	$ 8,617,075
%Change (year over year)			8.4%	1.9%	(4.9%)	15.4%

4.2 EP 6.

Ref: Exhibit 4, Tab 1, Schedule 2

a. Please provide the actual level of embedded distributor costs included in OM&A expenses for each of 2010 through 2013. If actual 2013 costs are not available, please provide the forecast for 2013.

HCHI Response

Embedded Distributor costs for sub-transmission charges billed by HONI for HONI embedded load as follows:

Embedded Distributor Sub-transmission Charges Included in OM&A

	2010 (8 Months - May 1 to December 31)	2011	2012	2013
Sub-Transmission Charges - Account 5085	$ 90,082	$ 180,564	$ 189,483	$ 246,227

b. Please provide the level of embedded distributor costs included in the 2014 OM&A forecast.

HCHI Response

The Embedded Distributor costs for sub-transmission charges billed by HONI for HONI embedded load in the 2014 forecast is $227,541. This number is to be updated with the HONI approved sub-transmission rates effective January 1, 2014 in conjunction with updating Staff IR # 36 a. to a 2014 forecast of $236,125.

c. Please confirm that there were no embedded distributor costs included in the 2010 Board approved level of OM&A. If this cannot be confirmed, please provide the amount included.

HCHI Response

HCHI confirms there were no Embedded Distributor costs for sub-transmission charges billed by HONI for HONI embedded load in the 2010 Board-Approved OM&A.

d. Please explain how the portion of the cost of servicing the embedded distributor that is allocated to an OM&A account is calculated.

HCHI Response

HONI bills HCHI on a gross load billing basis for sub-transmission charges for all embedded metering points including the points where HONI is embedded to HCHI. HCHI calculates the cost of servicing the embedded distributor by using the actual demand for the month, as read by HCHI for each of the metering points, and multiplies the kW by the appropriate sub-transmission rate. This is the amount booked each month to HCHI's OM&A as a cost of servicing the Embedded Distributor.

e. Please explain why the sub-transmission rates charged to HCHI by HONI are allocated to an OM&A account rather than tracked through a cost of power/transmission account.

HCHI Response

HONI did not have a method of separating their embedded load from HCHI's load charged for sub-transmission charges. The charges associated with HCHI's regular customers for sub-transmission are allocated to the appropriate Retail Settlement Variance Account ("RSVA") – Low Voltage (1550) to offset the revenue billed to HCHI's regular customers for low voltage rates. It is not appropriate to charge HONI's embedded load to this RSVA account as it is solely a cost of servicing the Embedded Distributor due to HONI's billing system constraints. The rate charged to recover these costs is the Wheeling Distribution revenue rate developed for the Embedded Distributor and not a Low Voltage or Retail Transmission rate.

4.2 EP 7.

Reference: Exhibit 4, Tab 1, Schedule 2

a. Please provide the level of the costs included in the OM&A costs for the 2010 Board approved figure, and the amounts included for each of 2010 through 2014 for Christmas light work and banners.

HCHI Response

The following table provides the requested information.

Banner & Christmas Light OM&A Costs – 2010 to 2014 Years

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year Interrogatory Responses
Banners	$ 5,895	$ 5,620	$ 2,638	$ 141	$ -
Christmas Lights	8,956	14,761	12,773	32,778	24,600
Total	$ 14,851	$ 20,381	$ 15,411	$ 32,919	$ 24,600

b. Please explain what is included in the costs associated with Christmas light work and banners.

HCHI Response

Christmas light work typically includes the installation and removal of decorative Christmas fixtures from utility poles. HCHI provides truck and labour or a third party contractor to work with community groups to install Christmas fixtures annually as a community benefit. Decorations are installed in the following communities: (i) Caledonia; (ii) Cayuga; (iii) Jarvis; (iv) Hagersville; (v) Selkirk; (vi) Dunnville; and (vii) Fisherville.

Beginning in 2011, and continuing in each of 2012, 2013 and 2014, HCHI has provided a one-time project and budgeted additional truck and labour to work with community groups to relocate Christmas fixture brackets lower on the utility poles. By lowering the fixture it, improves safety for HCHI staff who install the fixtures, by improving clearance to primary and secondary voltages. HCHI also used the opportunity to require that the electrical receptacles on the poles be brought up to current ESA standard and required that the

Business Improvement Areas (who are responsible for the Christmas brackets, fixtures and receptacles on behalf of the County) supply all material, an electrician and the ESA permits necessary to complete the work.

Across-road banners are located in Cayuga, Hagersville, Caledonia, Jarvis and Dunnville. In 2010 and 2011, HCHI installed and removed community banners at these locations as requested by Haldimand Count. HCHI also completed maintenance on the banner poles as required. Previously, the installation of these banners required the use of “Authorized Workers” due to the proximity to HCHI distribution equipment. This is no longer the case, and HCHI confirmed by measurement that all banner installations are located such a distance that “Authorized Workers” are no longer required to install banners.

4.2 EP 8.

Reference: Exhibit 4, Tab 2, Schedule 8

Please explain why the intervenor costs associated with the cost of service application have not been spread out over 5 years, similar to the legal and consulting costs.

HCHI Response

In response to this interrogatory, the cost awards for Intervenors associated with the 2014 Cost of Service ("COS") rate application in the amount of $55,000 have now been spread over the 5 year rate term. All updated tables and models that accompany these responses have been revised accordingly.

4.2 VECC 9.

Reference: E4/T2/S2

Please update Table 6 for 2013 actuals (unaudited)

HCHI Response

HCHI has updated Table 6 with 2013 actual (internally prepared and unaudited) financial statement results.

Table 6
Detailed OM&A Expense

OM&A Programs / Major Function	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Test Year Interrogatory Responses	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2010 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
OPERATING PROGRAMS								
Supervision and Engineering	499,249	468,918	556,881	630,949	590,838	670,136	39,187	170,887
Distribution Station Equipment	37,459	38,231	33,984	32,931	29,028	53,255	20,324	15,796
Overhead Distribution Lines	100,588	140,891	171,849	145,027	149,168	140,772	(4,255)	40,184
Miscellaneous Distribution Expenses	192,883	159,966	185,803	160,535	186,012	211,537	51,002	18,654
HONI Sub-transmission Charges Re: Servicing Embedded Distributor		90,082	180,564	189,483	246,227	236,125	46,642	236,125
Underground Distribution Lines	58,608	80,920	75,942	90,536	86,062	90,243	(293)	31,635
Distribution Transformers	237,657	214,336	221,347	307,729	106,670	221,132	(86,597)	(16,525)
Distribution Meters	276,493	243,038	234,767	368,290	312,709	292,440	(75,850)	15,947
Distribution Meters - Smart Meter Disposition				119,128			(119,128)	-
Customer Premises	17,277	18,483	7,941	16,878	9,069	19,218	2,340	1,941
Sub-Total	1,420,214	1,454,865	1,669,078	2,061,486	1,715,783	1,934,858	(126,628)	514,644
MAINTENANCE PROGRAMS								
Supervision and Engineering	129,706	129,856	127,417	125,697	111,563	145,626	19,929	15,920
Distribution Station Equipment	107,029	108,052	237,157	30,937	31,552	63,263	32,326	(43,766)
Overhead Distribution Lines Re: Poles, Conductor, Services	1,647,046	1,208,142	1,448,564	1,309,477	1,247,111	1,695,097	385,620	48,051
Overhead Distribution Lines Re: Tree Trimming	466,696	312,680	191,906	302,523	335,838	385,405	82,882	(81,291)
Underground Distribution Lines	155,391	185,007	154,826	251,655	160,980	190,204	(61,451)	34,813
Distribution Transformers	159,370	231,182	275,482	268,808	212,798	245,934	(22,874)	86,564
Distribution Meters	26,272	12,715	24,169	22,515	12,675	25,514	2,999	(758)
Sub-Total	2,691,510	2,187,634	2,459,521	2,311,612	2,112,517	2,751,043	439,431	59,533
COMMUNITY RELATIONS PROGRAMS								
General	5,450	7,172	8,112	28,576	36,336	44,720	16,144	39,270
Banners and Christmas Lights	23,386	14,851	20,381	15,411	32,919	24,600	9,189	1,214
Energy Conservation	18,000	20,620	16,932	18,885	160	-	(18,885)	(18,000)
Energy Conservation - Smart Meter Disposition				80,336			(80,336)	-
Sub-Total	46,836	42,643	45,425	143,208	69,415	69,320	(73,888)	22,484
BILLING and COLLECTING PROGRAMS								
Supervision	144,980	142,674	143,307	150,888	132,263	179,361	28,473	34,381
Meter Reading	212,609	272,680	140,029	209,281	278,828	311,043	101,762	98,434
Meter Reading - Smart Meter Disposition				396,886			(396,886)	-
Customer Billing	602,980	528,227	523,653	631,037	583,406	690,893	59,856	87,913
Customer Billing - Smart Meter Disposition				102,097			(102,097)	-
Customer Collecting	254,886	258,458	225,155	248,698	232,026	251,812	3,114	(3,074)
Bad Debts	30,000	39,405	57,029	63,473	110,453	94,049	30,576	64,049
Retail Services	73,968	64,544	65,779	65,506	66,674	91,776	26,270	17,808
Sub-Total	1,319,423	1,305,988	1,154,952	1,867,866	1,403,650	1,618,934	(248,932)	299,511
ADMINISTRATIVE and GENERAL PROGRAMS								
Board of Director Expenses	71,428	48,832	57,207	102,865	116,185	83,421	(19,444)	11,993
Management, Administrative, IT Services	1,197,345	1,089,256	1,204,131	1,264,829	1,123,757	1,357,699	92,870	160,354
General Office Expenses	35,720	48,639	19,447	(18,820)	49,210	24,968	43,788	(10,752)
Membership Fees & Subscriptions	41,615	40,905	42,932	45,771	47,380	47,915	2,144	6,300
Professional Fees (Auditing, Legal, Consulting)	169,432	59,816	197,402	106,398	287,665	142,352	35,954	(27,080)
Professional Fees (Consulting) - Smart Meter Disposition				5,199			(5,199)	-
Professional Fees (Outside Computer Services)	232,674	195,029	208,435	276,309	293,753	311,898	35,589	79,224
Professional Fees (Outside Computer Services) - Smart Meter Disposition				24,027			(24,027)	-
Property and Liability Insurance	64,508	55,414	76,593	77,948	88,175	89,813	11,865	25,305
Property Insurance - Smart Meter Disposition				1,517			(1,517)	-
ESA and Regulatory Fees	101,208	199,669	112,523	87,382	94,692	120,245	32,863	19,037
Property Taxes	53,447	51,140	47,695	47,199	45,418	48,110	911	(5,337)
Special Purpose Charge	-	94,692	46,517	330	-	-	(330)	-
LEAP Funding	-	-	16,500	16,500	16,500	16,500	-	16,500
Sub-Total	1,967,377	1,883,392	2,029,382	2,037,454	2,162,735	2,242,921	205,467	275,544
Total	7,445,359	6,874,522	7,358,358	8,421,626	7,464,100	8,617,076	195,450	1,171,716

4.2 VECC 10.

Reference: E4/T1/S2/pgs.10-11 & Table 6 Re: Bad Debt

a. Please explain how the 2014 bad debt forecast is calculated.

<u>HCHI Response</u>

HCHI calculates the Bad Debt forecast by reviewing finaled aged arrears over 90 days for the current year plus the two previous years. The Bad Debt forecast is decreased by the average annual dollars recovered through a third party collection agency. The Bad Debt forecast will include miscellaneous receivable accounts deemed to be uncollectable.

b. Please provide the amount of the "large MAR from 2010" and clarify whether HCHI proposes to collect this amount in 2014 rates.

<u>HCHI Response</u>

The large Miscellaneous Accounts Receivable ("MAR") from 2010 in the amount of $21,661 was written off by HCHI in 2013. HCHI does not propose to collect this specific MAR in 2014 rates but has provided for other MARs that may become uncollectible in the Bad Debt expense in the 2014 Test Year. This particular 2010 MAR was on account of damages to HCHI's distribution system as a result of a motor vehicle accident ("MVA") involving a driver residing in and insured in the province of Quebec, which made it very difficult to collect even after engaging a legal firm in Toronto that had a Quebec office.

Prior to January 2012, the MVA reports HCHI was provided with from the local Ontario Provincial Police ("OPP") contained all pertinent information in order to invoice the party damaging HCHI's distribution system. In January 2012, HCHI was informed by the local OPP that, due to privacy legislation, they could not provide it any longer with the driver's name, address and telephone number. The insurance company and policy number have remained on the MVA report. HCHI has now taken the route of invoicing the insurance company directly but in some cases, the driver has not put the claim through their insurance company and it is not on file with them which results in a bad debt to HCHI. Some insurance companies are also difficult to deal with in that they will only pay out partial claims and a portion of the invoice remains unpaid and becomes a bad debt to HCHI.

4.2 VECC 11.

Reference: E4/T2/S1/pgs. 7-12

Re: Smart Meter Incremental Costs (the purpose of this interrogatory is to understand the elements which have caused billing and collection to increase from 2010 to 2014).

a. Please compare the cost components of Billing and Collection accounts 5305, 5310, 5315, 5320,5325, 5335, 5340 for 2010 for Board approved 2010, 2010 actuals and 2014 forecast.

HCHI Response

The following table provides the cost components for all of the above noted accounts for comparison for each of 2010 Board-Approved, 2010 Actuals and 2014 Test Year.

Billing and Collecting Accounts
Cost Components

		2010 Board Approved	2010 ACTUAL	2014 Test Year
	Supervision			
01.5305.001	Billing & Collecting Supervision	$ 80,652	$ 77,743	$ 99,221
06.5305.001	Customer Care Systems Supervisor	$ 64,328	$ 64,931	$ 80,140
		$ 144,980	$ 142,674	$ 179,361
	Meter Reading			
01.5310.001	Meter Reading Expense-Regular	$ 5,900	$ 3,045	$ 7,728
06.5310.001	Meter Reading Expense-Regular	$ 193,280	$ 266,435	$ 500,458
01.5310.002	Meter Reading Expense-Finals	$ -	$ 45	$ -
06.5310.002	Meter Reading Expense-Finals	$ 13,429	$ 3,155	$ 3,806
		$ 212,609	$ 272,680	$ 511,992
	Customer Billing			
01.5315.001	Customer Billing	$ 602,980	$ 528,227	$ 690,893
		$ 602,980	$ 528,227	$ 690,893
	Collecting			
01.5320.00*	Collecting	$ 254,886	$ 258,458	$ 251,812
		$ 254,886	$ 258,458	$ 251,812
1-550-5325-00-00	Collecting - Cash Over/Short	$ -	$ 0	$ -
		$ -	$ 0	$ -
	Provision for Bad Debts			
1-550-5335-01-00	Bad Debts	$ 30,000	$ 46,758	$ 94,049
1-550-5335-02-00	Recovery of Bad Debts	$ -	$ (7,354)	$ -
		$ 30,000	$ 39,405	$ 94,049
	Miscellaneous			
02.5340.001	Retail Services-Charges	$ 58,001	$ 53,740	$ 64,882
02.5340.002	Retail Services-Strs	$ 18,458	$ 12,021	$ 12,080
02.5340.003	Services-WSS Web	$ 28,080	$ 30,499	$ 31,884
06.5340.003	Services-WSS Web	$ 4,626	$ 3,600	$ 4,236
02.5340.004	Interrogations-Peterborough Utilities	$ 23,169	$ 34,508	$ 42,029
02.5340.005	Services - Admin Fee (collected)	$ -	$ (6,048)	$ -
06.5340.004	Interrogations-Peterborough Utilities	$ 14,659	$ 14,964	$ 21,707
		$ 146,993	$ 143,285	$ 176,818

b. **Please compare and contrast the components of actuals 5315 Billing for 2010 actuals as compared to 2014 forecast costs.**

<u>HCHI Response</u>

The comparison of the 2010 Actual to 2014 Forecast for customer billing (account 5315) shows an increase of $162,667, and includes the following:

- $82,500 – addition of one full time employee (Sync Operator).;
- $31,000 – addition of one temporary Customer Service Representative position within the Customer Service department which was used to backfill an employee being used exclusively for the LDC-IESO MDM/R enrolment testing period;
- $30,000 - annual wage increases;
- $48,000 - annual Canada Post postage increases
  - 2010 = $0.57 / mail piece
  - 2014 = $0.63 / mail piece (Q1), $0.75 / mail piece(Q2-3-4);
- $4,000 - bill stock, envelopes, office supplies and staff training;
- $(25,000) - reduction in manual meter reading costs due to utilizing AMI meter data; and
- $(7,907) – allocation of indirect costs specific to the Ontario Power Authority ("OPA") Conservation and Demand Management ("CDM") program costs.

c. **Please provide a breakdown of the incremental smart meter related OM&A costs forecast to be incurred in 2014 (as compared to the 2010 actual year).**

<u>HCHI Response</u>

OM&A "Meter Reading Expense" account 5310 captures costs in regards to various meter reading activities. The cost variance between 2010 actual and 2014 forecast is $239,000. This variance is caused by the reoccurring annual operating costs for 3rd party AMI smart meter network management and operational data storage. The annual incremental costs are noted below.

- Operational Data Storage = $40,000/yr.
- AMI meter data management + network infrastructure = $199,000/yr.

4.2 VECC 12.

Reference: E4/T1/S2/pg.11

Please provide all training, conference and travel costs for each year 2010 through 2014.

HCHI Response (Sherry – make 2013 “actual, not bridge)

HCHI’s costs for training, conference and travel for its Administrative staff are as follows:

- 2010 - $8,117
- 2011 - $2,799
- 2012 - $3,676
- 2013 - $8,960
- 2014 - $10,947

4.2 VECC 13.

Reference: E4/T2/S6

For each year in the period 2010 through 2014 please provide the amounts for:

a. EDA Fees;

HCHI Response

- 2010 - $38,800
- 2011 - $40,000
- 2012 - $42,200
- 2013 - $44,570
- 2014 - $45,186

b. MEARIE Insurance Premiums;

HCHI Response

- 2010 - $33,556
- 2011 - $54,467
- 2012 - $55,369
- 2013 - $65,282
- 2014 - $66,471

c. GridSmartCity LDC Membership (if any);

HCHI Response

HCHI does not have a GridSmartCity LDC Membership.

d. Other LDC memberships (please describe).

HCHI Response

Miscellaneous Subscriptions:

- 2010 - $2,105
- 2011 - $2,932
- 2012 - $3,189
- 2013 - $3,080
- 2014 - $2,729

4.2 VECC 14.

Reference: E4/T2/S6

MEARIE Purchases:

a. **HCHI purchase services from MEARIE Management Inc. and MEARIE Insurance. The evidence states that the procurement method was an RFQ. Please explain when last RFQs for these purchases were undertaken. Describe how they were advertised and how many offers were tendered.**

<u>Response</u>

HCHI participates in the MEARIE Management Inc. ("MMI") Employee Benefit Program, under which MMI is the governing Policyholder, and HCHI engages the services of MMI to act as its administrator with respect to benefit offerings elected under the MMI program. MMI warrants that it will use commercially reasonable efforts to provide its services. MMI most recently conducted a RFP during 2013 for employee benefits effective January 1, 2014.

HCHI subscribes to the MEARIE Insurance Program with respect to comprehensive general liability coverage. MEARIE provides stable insurance programs with competitive rates and specialized coverage, customized for the electricity sector, through a group-buying approach.

With respect to both MMI and MEARIE, HCHI is not a party to their form of advertising for quotations or how many offers are tendered.

b. **Does HCHI purchase any services from any other MEARIE/EDA related companies (other than for insurance and benefit provisions)? If yes please provide the annual amount and procurement method.**

<u>Response</u>

As noted at Exhibit 4/Tab 2/Schedule 6 in Tables 11, 12 and 13, there are no other amounts in excess of the $64,000 materiality threshold listed for any other MEARIE/EDA related companies.

4.3 Are the applicant's proposed operating and capital expenditures appropriately paced and prioritized to result in reasonable rates for customers, or is any additional rate mitigation required?

4.3 Staff 18. Distribution Rate Impacts

Reference: ***Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013: 5.4 Capital Expenditure Plan***

HCHI's capital expenditure plan is based on a Distribution Asset Management Plan ("DAMP") that was developed in 2009 with the assistance of Kinectrics Inc. The Plan was approved in HCHI's 2010 Cost of Service application and updated in 2013.

a. In its annual capital planning and implementation for the years 2009 to 2014 did the HCHI take into account the cumulative impact its capital expenditures would have on rates in 2014?

<u>HCHI Response</u>

Yes, the cumulative impact on rates was considered.

b. If HCHI did consider 2014 rate impacts, what changes ensued from these considerations?

<u>HCHI Response</u>

The cumulative impact was considered; however, no changes ensued from these considerations. The Distribution System Plan outlines the need for increased capital spending in future years.

4.3 Staff 19. Prioritization Model

Reference: ***Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, p47 of 66 – Prioritization Model***

In the second paragraph under system service, HCHI states that it is replacing the Prioritization Model with a new approach based on the DS Plan and Chapter 5 Filing Requirements investment criteria and drivers to prioritize projects.

a. Please state the investment criteria and drivers HCHI is referring to and how they affected prioritization.

HCHI Response

HCHI used its Prioritization Model (see response to Staff IR # 3) for prioritizing the capital projects. The OEB's *Chapter 5 Consolidated Distribution System Plan Filing Requirements Table 1 – Investment Categories & Example Drivers and Projects/Activities* was used to categorize the projects within the four investment categories.

HCHI has plans to revise or develop a new Prioritization Model in 2014 using the new Chapter 5 criteria for projects planned for 2015 to 2018.

HCHI has not yet updated the Prioritization Model with the new *Chapter 5 Filing Requirement* criteria. HCHI has attempted to categorize the investments using its existing Prioritization Model and placing them within the four investment categories.

b. What are the consequences of the reprioritization as they pertain to service, safety and reliability? How has HCHI adjusted its approach to risk management to account for any changes?

HCHI Response

Reprioritization has not occurred.

c. Please state any projects that have been reprioritized and the driver that caused the reprioritization.

<u>HCHI Response</u>

Reprioritization has not occurred.

d. What risks to the system would such a re-prioritization create?

<u>HCHI Response</u>

There are no risks to the system as the reprioritization has not occurred.

e. Please confirm that all re-prioritizations have been included in the 2014 – 2018 plans?

<u>HCHI Response</u>

Reprioritizations have not occurred for the 2014 – 2018 plans.

4.3 Staff 20. Capital Expenditures

Reference: ***Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013:***
p. 59 – Capital Investment Expenditure Level;
p. 60 – Five Year Forecast;
p. 63 – Shifts in Forecast vs. Historical Budgets by Category;

Chapter 2 Filing Requirements Appendix 2 AB – Capital Expenditure Summary from Chapter 5

In explaining its capital expenditure level, HCHI lists 10 factors that affect the level of Capital Expenditures over the five years commencing with 2014. The first factor relates to System Renewal and relies on the two Asset Condition Assessments performed in 2009 and 2013 by Kinectrics Inc. HCHI states that the latter study suggested an average annual investment of $3.1 million. However, in Appendix 2 AB, for System renewal, it appears that HCHI has not budgeted $3.1 million.

a. **Please comment on the difference between Appendix 2-AB and the 2013 Asset Condition Assessment recommendations.**

<u>HCHI Response</u>

Although HCHI has determined a need for $3.1 million for System Renewal the entire amount is not budgeted as capital expenditure, as a portion of System Renewal is completed under operating and maintenance ("O&M") budgets.

HCHI budgets replacement of some asset categories under O&M (see Table 5-18 on page 49 of the Distribution System Plan (Appendix A)). Asset categories including Pole Top, Pad-Mounted and Step-Down transformers are all run to failure assets and are typically replaced like for like upon failure. Their replacement would be completed under O&M budget activities, unless they are being replaced prior to failure due to capacity increase or as part of a capital project.

Gang Operated OH line switches, Pad-mounted switchgear and underground XLPE Cables (in-duct) would also be replaced as part of the O&M budget. The rationale for each replacement can be found in detail in the Distribution Asset Management Plan at Section 7.3 on pages 38 to 54.

b. Please identify the sources for Kinectrics' cost estimates and the year the costs were developed, and comment on their applicability to the projects being assessed.

HCHI Response

In the 2009 Asset Condition Assessment Report prepared by Kinectrics, the unit costs were developed by HCHI using 2008 material cost, labour and truck data; that is, with the exception of Asset Category "B" Air Blast Circuit Breakers and Asset Category "I" Primary Underground Cable – XLPE. HCHI had little experience with costs associated with those replacements and requested Kinectrics provide "industry" average costs. The 2009 unlevelized capital plan was developed by multiplying the estimated annual sustainment quantity by the unit costs.

In the 2013 Asset Condition Assessment Report, Kinectrics did not complete any costing within their scope of work. Kinectrics provided Table IV-3 Twenty Year Condition – Based "Flagged for Action" Plan Appendix H (page 27). HCHI reviewed the unit costs used for the 2009 ACA and updated the costs to current labour and truck rates. The estimated truck and labour hours were reviewed for each asset category and updated costs on typical material lists from HCHI's current inventory, based on USF framing standards. The updated unit costs were then used to develop an unlevelized sustainment dollars amount (refer to Table 5-18 on page 49 of the Distribution System Plan). An "Average Annual Sustainment" amount of $3,134,000 was developed for the purposes of levelizing spending in any year to smooth out costs.

HCHI states that due to the projects being in "the most preliminary stages of planning", costs are uncertain, and so an allowance is forecast to bridge the gap between the forecast levels and the project costs.

c. Is there any risk that high priority projects result in total annual costs above the forecast levels? If so, what recourse would HCHI take?

HCHI Response

Yes, there is a risk that high priority projects result in project costs that are above the forecast levels. HCHI reviews CAPEX spending on a monthly basis and also reviews the overall total project spending. HCHI will not spend in excess of the total of its own Board-Approved CAPEX. A lower priority project may be deferred if necessary to ensure that the total CAPEX is not exceeded.

d. Has HCHI now performed its prioritization? In what way do these priorities reflect customer interests?

<u>HCHI Response</u>

HCHI has not performed its prioritization using the Chapter 5 criteria.

e. Has HCHI more formalized forecasted costs?

<u>HCHI Response</u>

HCHI is in the process of determining more accurate forecast costs based on detailed designs for 2014. The final designs and cost estimates are not complete to date.

f. If the answers to d. and e. are yes, please update forecasts.

<u>HCHI Response</u>

Response not required based on responses to d. and e.

g. What performance factors will HCHI be monitoring to ensure that the capital expenditures meet the reliability and quality of service at a reasonable cost?

<u>HCHI Response</u>

Performance factors used to monitor the success of the capital expenditures are discussed in the response to Staff IR # 5 d.

HCHI states in Forecast vs. Historical Budgets by Category, System Access that there are increases in developer rebates over previous years.

h. Please explain developer rebates with reference to the applicable sections of the Distribution System Code.

HCHI Response

HCHI understands that it complies with Section 3 of the DSC with respect to developer rebates.

For residential subdivision development projects, HCHI provides the developer it's *Electrical Distribution Requirements for Residential Subdivisions.* The developer provides HCHI the distribution system designs for approval and purchases materials and constructs the distribution system at its expense. Upon approval, the developer constructs the distribution system. HCHI will connect the new distribution system to the existing system. The developer will provide HCHI its construction and material costs that the developer incurred to build the system. The total costs (developer costs and HCHI's costs for the distribution system) are inputs (along with other inputs) into the *Municipal Electricity Association Model on Economic Evaluation of Expansions Projects* (the "Model"). The Model determines the dollar amount of the developer rebate.

Overhead distribution system expansion projects are treated similarly from a financial perspective in that HCHI requests a deposit from the customer requesting the expansion. An economic evaluation is completed using the same Model after actual expenses are finalized. This may result in either a refund of a portion of the customer's deposit or additional funds charged to the customer for the expansion.

This process ensures that the appropriate capital contribution is collected from the developer or customer.

i. Please describe how increases in developer rebates affect the revenue requirement, if at all.

HCHI Response

If there are increases in the developer rebates, this similarly reduces the capital contribution netted against the related cost of the capital assets assumed. Accordingly, this increases the regulated return on capital which increases the revenue requirement.

HCHI states in the last paragraph on page 64, for System Service, expenditures are included for rear-lot or difficult to access infrastructure.

j. Will HCHI be replacing this infrastructure with above ground or below ground plant?

HCHI Response

The replacement of this infrastructure is intended to be overhead. There may be areas where space is limited, because of very narrow road right-of-ways and close proximity of buildings to the road, where underground may be the only solution. The underground option along the Lake Erie Shoreline areas is only used if an overhead option is not possible.

k. Please provide a justification for any plans that are not a least cost option, with reference to customer engagement, expectations and productivity.

HCHI Response

HCHI uses the least cost options for all overhead projects; that is, unless underground is the only option. Again, the least costs option is considered on all projects.

4.3 Staff 21. REG System Access

***Reference:** Appendix "D" to Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, -Renewable Energy Generation Plan*

HCHI has projected a Capital Cost for REG in 2014 at $1,523,383, at page 5 and on page 3 states that it is preliminary "as the location and quantity of renewable generation project is, for the most part, unknown at this time."

a. Has HCHI any more firm indication as to timing and estimated costs for REG System Access investments?

HCHI Response

The projected capital cost for REG in 2014 at $1,523,383 includes $900,000 for distribution system expansions (calculated at 10 MW x $90,000 per MW). HCHI has received 5 applications to date (2014) to conduct Connection Impact Assessments for 500 kW PV-Solar projects all within the same geographic location. The connection of these five projects will involve a distribution system expansion. Total costs for this are not known at this time but it is expected that HCHI's share may be $90,000 per MW x 2.5 MW = $225,000. HCHI would seek to recover $186,750 ($225,000 x 0.83) through the Provincial Benefit rate recovery process. The proposed connection date for these projects is 2015.

b. What will be the priority once REG developers indicate their timing? For example, will System Renewal, and System Service work be delayed, or will the developer have to wait until HCHI can schedule the System Access work for them? Please explain, with reference to any applicable timelines and the DSC.

HCHI Response

It is expected that System Renewal and Service work will continue as planned. Generators that request System Access type work will be accommodated with HCHI deploying additional resources, if required, to meet the timelines as required under the DSC.

c. Is acquisition of the SCADA to commence regardless of the actual commitment of the renewable generation projects?

HCHI Response

HCHI has planned to develop a SCADA implementation and development plan in 2014. HCHI currently has 3 electronic reclosers that have remote transfer trip capabilities with four large DG projects. HCHI has limited communications with these devices. HCHI expects that more similar devices will be required in the forecast years. HCHI has in total 11 electronic reclosers connected to its distribution system. These reclosers are located throughout HCHI's large service territory and may require truck rolls to determine status and to perform operation. Planning the acquisition of a SCADA system is scheduled for 2014. The system would be a single license model that will be scalable in future years as devices are added. Set up and training of the system would also occur in 2014.

d. Based on the above, if required, please update Appendix 2-AB

HCHI Response

Based on the responses above, an update to Appendix 2-AB is not required.

4.3 VECC 15.

Reference: E2/T2/S1/pg.2 Table 4 / E2/T2/S3/pg.1-3

HCHI had Gross Fixed Assets in 2010 which were $719,253 less than forecast and notwithstanding that its capital expenditures in that year were only $43,235 ($3.3m – 3.256m). This variance is explained at Schedule 3. However, we are unable to reconcile either the gross fixed asset variance or the capital expenditure variance with the figures given at pages 1 to 5 of Schedule 3. The explanation appears to show a comingling of capital expenditure variances and asset variances (e.g. Account 1820 and 1930)

a. Please provide a reconciliation which shows the capital expenditure variance of $43,235.

HCHI Response

The actual variance from the 2010 Board-Approved capital additions of $3,312,301 and the 2010 Actual capital additions of $3,256,765 is $55,536. The reconciliation for this variance is detailed by asset category in the table that follows:

Reconciliation of Capital Additions
2010 Actual to 2010 Board-Approved

	2010 Actual	2010 Board-Approved	Variance
Distribution Station Equipment <50 kV	$ -	$ -	$ -
Poles, Towers & Fixtures	915,291	726,388	188,903
Overhead Conductors & Devices	895,166	572,938	322,228
Underground Conduit	64,293	364,927	(300,634)
Underground Conductors & Devices	260,564	214,503	46,061
Line Transformers	483,494	515,365	(31,871)
Services (Overhead & Underground)	124,963	196,004	(71,041)
Meters	18,218	87,763	(69,545)
Land			0
Land Rights (Formally known as Account 1906)			0
Buildings & Fixtures	32,033		32,033
Office Furniture & Equipment (10 years)	4,925	5,336	(411)
Computer Equipment - Hardware	69,180	18,676	50,504
Computer Equipment - Software	285,190	429,068	(143,878)
Transportation Equipment	332,199	273,600	58,599
Tools, Shop & Garage Equipment	90,319	39,333	50,986
Communications Equipment	11,430	0	11,430
Contributions & Grants	(330,500)	(131,600)	(198,900)
Totals	$ 3,256,765	$ 3,312,301	$ (55,536)

b. Please provide a reconciliation of the gross fixed asset variance of $719k.

<u>HCHI Response</u>

This variance of $719,253 has been detailed by asset category in Exhibit 2 / Tab 2 / Schedule 2 / Table 16 with variance explanation of the amounts exceeding materiality threshold in Exhibit 2 / Tab 2 / Schedule 3 / Pages 1 to 3.

4.3 VECC 16.

Reference: E2/T2/S3/pg.1

Please explain if the Nanticoke Distribution Station removal was identified in the last cost of service application (2010). If not, please explain the omission.

HCHI Response

A capital project to eliminate the requirement for the Nanticoke Distribution Station was completed in 2008 and detailed in the 2010 Cost of Service Application (EB-2009-0265) at Exhibit 2 / Tab 2 / Schedule 3 on page 42 of 65. HCHI made reference to the Nanticoke Distribution Station, although not explicitly by name, in Exhibit 4 / Tab 2 / Schedule 1 / on page 3: "*HCHI has 1 decommissioned substation to be dismantled in a future year*" and in Exhibit 4 / Tab 2 / Schedule 3 on page 3: "*As well, the remediation of soil has been a cost in a few years at the decommissioned distribution stations ("DS")…and Nanticoke DS scheduled for 2010).*"

As currently indicated in Exhibit 2 / Tab 2 / Schedule 3 on page 1 "*This DS was dismantled in 2010 and removed from HCHI's books.*"

4.3 VECC 17.

Reference: E2/T2/S3/pg.3

Please explain when the Asset Management Software was purchased and for how much.

<u>HCHI Response</u>

The asset management software was not purchased in 2010 and the amount was subsequently reallocated to other capital projects.

4.3 VECC 18.

Reference: E2/T2/S1/pg.7

Please provide a description of how the capital contribution forecast for 2014 is calculated.

HCHI Response

The 2014 Capital Contribution estimate of ($190,000) was forecast in the same manner as the 2013 amount. The 2013 amount was based on an historic actual average of the previous 4 years.

4.3 VECC 19.

Reference:E2/T5/S2

Please update Table 22 to include 2013 actual capital expenditures and if necessary any fallout revision to 2014 expenditures.

<u>HCHI Response</u>

HCHI has updated Table 22 with 2013 "actual" capital expenditures and included a "carry over" column showing capital projects not complete in 2013 but the amounts to be carried over and completed in 2014. (Note: the 2014 "forecast" amount does not include the 2013 carry over amount).

Table 22
Capital Expenditure Summary by Investment Category

CATEGORY	Historical Period (Actual)						Forecast Period (Planned)				
	2009	2010	2011	2012	2013		2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Actual	Carry Over					
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*				
System Access	928	1,004	887	4,848	1,336	10	1,978	1,456	1,330	1,406	1,365
System Renewal	928	1,210	769	498	402	--	375	950	1,425	1,300	1,350
System Service	1,221	189	2,617	3,203	2,000	1,131	2,946	2,200	2,175	2,410	2,100
General Plant	1,114	825	676	651	459	--	680	698	489	437	464
Total Capital Expenditure	$ 4,191	$ 3,228	$ 4,949	$ 9,200	$ 4,197	$ 1,141	$ 5,979	$ 5,304	$ 5,419	$ 5,553	$ 5,279
System O&M	$ 2,909	$ 2,794	$ 3,078	$ 3,158	$ 3,898	--	$ 3,606	$ 3,664	$ 3,722	$ 3,782	$ 3,842

Notes to the Table:
Table 22 revised to include 2013 Actual Capital Expenditures and show carry over capital expenditures to 2014.

5 Public Policy Responsiveness

5.1 Do the applicant's proposals meet the obligations mandated by government in areas such as renewable energy and smart meters and any other government mandated obligations?

5.1 Staff *22.* REG Plan

Reference: ***Appendix "D" to Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013, - OPA's Letter of Comment dated September 11, 2013 Re: Haldimand County Hydro Inc. Renewable Energy Generation (REG) Plan***

Regarding Renewable Energy Generation ("REG"), in the OPA's letter of comment it is apparent that there is a difference in HCHI and the OPA's accounting of the FIT and microFIT projects involved. Board staff have developed the following table from the application: In the following table developed by Board staff, the number of OPA contracts offered is compared to the number of projects claimed by HCHI.

OPA - HCHI REG Projects Comparison

	OPA Contracts	Total kW	HCHI Plan	Total kW
microFIT	214	2,050	190	1,818
FIT	28	5,715		
RESOP	4	30,500	4	30,500

a. **The OPA letter states that the discrepancy from the number of projects is because 17 have not been connected. However, that does not account for all of the discrepancies. Please provide a fuller explanation of the discrepancies.**

HCHI Response

The *OPA – HCHI REG Projects Comparison* table above, prepared by Board Staff, contains an error in that it does not include 11 projects totaling 1,361 kW as part of the "HCHI Plan" column, that are listed on p. 3 of the REG Plan (Appendix C of the DS Plan). The discrepancy of "17" can be attributed to the date upon which HCHI prepared the data. HCHI reports projects that are connected and the OPA reports projects that are offered contracts.

The OPA's "Letter of Comment" dated September 11, 2013 also states "*The discrepancy from the number of projects in HCHI's Plan is because 17 of the projects have not yet been connected...*" The number will always be higher at any given time as projects move through the design and construction phase following a contract offer.

b. In what years will all the applications for which the OPA offered contracts for microFIT and FIT be completed?

HCHI Response

This is a function of the quantity of the applications and the size (MW) of the applications. At some point in time, all of the available capacity to connect generation will be allocated. HCHI does not know what year this will occur. As far as projects that have been offered contracts thus far, HCHI expects to connect them in 2014 and 2015.

c. Please indicate the estimated amount of the connection costs and in which year they occur. Please identify the parties responsible for bearing these costs.

HCHI Response

The generator is responsible for all of the connection costs. The table below contains the estimated connection costs per year.

	2009	2010	2011	2012	2013
microFIT Connected	1	35	114	38	35
microFIT Connection Costs	$ 163.71	$ 5,729.85	$ 18,662.94	$ 6,220.98	$ 5,729.85
FIT Connected	0	0	0	9	6
FIT Connection Costs	$ -	$ -	$ -	$ 152,814.48	$ 126,160.33

d. Are these costs included in Appendix 2–AB? If not please include in the update to Appendix 2-AB that arises from the interrogatories.

HCHI Response

MicroFIT and FIT connection costs, paid for by the generator, are capitalized with an offsetting credit to capital contributions, resulting in a net impact of zero.

5.1 Staff *23.* System Service/REG Plan

Reference: Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013:
p. 48 REG Investments;
p. 53 Table 5-19 Capital Expenditure Summary;
p. 50 Smart Grid Activities;

Distribution System Code ("DSC"), section 3.2.

In describing the REG investments, HCHI states that a SCADA system and a new breaker for the Dunnville TS will be acquired as REG investments. In Smart Grid Activities HCHI states that the SCADA will not be used only for control of REG facilities, but that it will interact also with other data gathering information systems.

a. Please confirm that the SCADA system is included in the item "REG Expansion Cost Cap (HCHI 17% Direct Benefit share)" in Table 5-19 Capital Expenditure Summary, or if not, state where it is included.

HCHI Response

The SCADA system total costs are included in the renewable capital expenditures amount of $246,000 as identified in the REG Plan. The SCADA system is considered a "renewable enabling improvement" (i.e. to be funded 94% from Provincial Recovery and 6% from HCHI CAPEX). The HCHI CAPEX portion of $14,760 would be included under General Plant - Information Technology ("IT") expenditures.

b. Please explain the rationale for including the SCADA system as a REG investment in General Plant.

HCHI Response

The SCADA system (HCHI's 6% of the investment) was included as General Plant as it was categorized as an IT investment.

c. Please provide a comprehensive description of the inter-relationship/integration of the information and control facilities which are planned. This should include the Information Technology investments (GIS, AMI ODS etc.) the Smart Grid activities Investments

(Grid Sense Line Trackers, Data Pac concentrator, IESO smart meter events), and the REG investments (SCADA).

HCHI Response

In 2014, HCHI has planned to engage a consultant to assist with developing a strategy to implement a SCADA system with the intent of connecting the data outputs of some of the stand-alone systems that are currently in place. This engagement and analysis is still to take place.

It is expected that HCHI's current meter technology (i.e. Line Trackers, Wholesale Meters, Reclosers, and AMI data) will provide inputs into the proposed SCADA system.

d. SCADA could also be considered a System Service expenditure. Please explain the rationale behind classifying SCADA as System Access.

HCHI Response

HCHI has not considered SCADA as either a System Service or System Access expenditure. HCHI's portion (6%) of the renewable enabling improvement would be allocated as a General Plant – IT investment.

e. Please provide justification for considering investments in the SCADA system and the breaker installation as qualifying for Provincial Benefits.

HCHI Response

HCHI has considered investment in the SCADA system as qualifying for Provincial Benefits as it is defined as a "renewable enabling improvement" as per the DSC section 3.3.2. (g).

> "3.3.2 Renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities are limited to the following:
>
> > (a) modifications to, or the addition of, electrical protection equipment;
> > (b) modifications to, or the addition of, voltage regulating transformer controls or station controls;
> > (c) the provision of protection against islanding (transfer trip or equivalent);

(d) bidirectional reclosers;
(e) tap-changer controls or relays;
(f) replacing breaker protection relays;
(g) Supervisory Control and Data Acquisition system design, construction and connection [emphasis added]**;**
(h) any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows; and
(i) communication systems to facilitate the connection of renewable energy generation facilities."

The Provincial Benefit calculations were determined as per the *Report of the Board EB-2009-0249 Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09.* The Provincial Benefit calculation is determined as 94% from Provincial Benefit and the Direct Benefit calculation is determined as 6% from HCHI customers.

HCHI's rationale with respect to its treatment of the Dunnville TS Breaker position purchase is further explained on pages 17 – 18 of the REG Plan, contained as Appendix C of the Consolidated DS Plan, as follows:

"Project 2
On October 7, 2013 a Connection Cost Recovery Agreement (CCRA) - MINI was executed between HCHI and HONI for the purchase of an additional breaker position to be installed as part of HONI's construction project at Dunnville TS for replacement of transformers that are at 'end of life'. The project involves rebuilding the station and replacing two 15/18/23 MVA transformers with two 25/33/42 MVA transformers. The project will also include new structures, breakers, and relay equipment. Installation of the new breaker at the same time has cost savings related to engineering, procurement, construction and deployment of staff and equipment. The installation of the two transformers increases the thermal capacity of the station and additional capacity for DG is anticipated. Since there are only two feeders at the TS (one HONI owned and one HCHI owned) the additional breaker provides an alternate feeder that can accommodate additional capacity for DG. The additional breaker is considered an expansion to the distribution system. HCHI recognizes that HCHI customers will also benefit in part from the new breaker. The benefit to HCHI customers is determined in the following way. The load capacity on the feeder through the new breaker position = 20 MW. HCHI would reconfigure circuits and transfer 10 MW of load from the existing feeder (31M1) to the new feeder utilizing 50% of the load capacity. Therefore, the remaining 50 % of the total cost of $805,765.00 can be attributed to the expansion for REG projects. The costs are calculated as follows:

Total expenditure for additional breaker position		$805,765.00
Less (2013 progress payment)		($51,000)
Balance due in 2014		$754,765.00
2014 Cost Calculations		
HCHI rate payers benefit	$754,765.00 x 50 %	= $377,382.50
REG Cost recovery balance		$377,382.50
Provincial rate payer	$377,382.50 x 83%	= $313,227.48

HCHI rate payers	$477,382.50 x 17%	= $ 64,155.03
Total HCHI rate payer cost		$377,382.50 $ 64,155.03 **$441,537.50**”

f. HCHI states that the SCADA costs are distributed 50/50 to the REG Plan and the Capital Expenditure Plan. Please provide substantiation for this distribution.

HCHI Response

HCHI is not allocating the SCADA costs 50/50 to the REG Plan and the Capital Expenditure Plan. Page 48 of the Consolidated DS Plan should have a paragraph separation after the statement “*REG Investments in General Plant include a SCADA system to monitor and operate devices in the field. These expenditures are apportioned using the renewable enabling improvement cost sharing formula as per the Distribution System Code section 3.2*.” It is intended that the cost sharing be calculated as per the response in e. above.

5.1 Staff 24. Smart Grid

Reference: ***Exhibit 2 Appendix "A"; Consolidated Distribution Plan, November 4, 2013 p. 54 of 66 – Conservation and Demand Management***

HCHI state that they have plans to utilize a smart meter communication protocol for Zigbee communication devices. However, there have been delays.

a. Please provide an overview of the "Zigbee communication based solution" and its function, and describe whether and how it will be integrated with the proposed SCADA.

HCHI Response

The Sensus AMI smart meter that HCHI utilizes for the majority of its customers has the ability to transmit data from the meter to an in-home-display (IHD) utilizing Zigbee communication protocol for the purpose of conservation.

In regards to the integration of Zigbee into the proposed SCADA, see response to Staff IR # 23 c.

b. Please state the causes for the delay in the Zigbee solution.

HCHI Response

The delay for deploying the Zigbee solution is due to the following two items:

1. The Sensus Regional Network Interface (RNI) software required an upgrade to accommodate the ability of over-the-air programming and management of Zigbee-enabled meters. At the time of the application submission, the delivery of the RNI upgrade was expected for the end of Sept 2013. That delivery date has passed and is now expected to be released closer to the end of Q1/2014.
2. Since the new RNI software was a significant upgrade, it was subject to an external security audit to ensure the new software was hardened to current IT security standards. The security auditor is Bell & Wurldtech.

c. Was there any customer engagement involved in deciding to use ZigBee?

HCHI Response

No customer engagement was done regarding the selection of the Zigbee protocol. The Zigbee communication protocol was selected by the meter manufacturer and AMI vendor (i.e. Sensus) and presented to its LDC customers for home area network communication solutions.

d. Please state any outcomes that would benefit the customers.

HCHI Response

If the question is in regards to the “benefits of using Zigbee in its smart meters”, then the benefit would be that HCHI can provide near-real-time load data to its customers which empowers them to better understand and manage their energy consumption. It also provides on-demand update commands to IHD customer devices which alleviates any responsibility for the customer to alter programmable settings (i.e. TOU structures and rate changes within the IHD).

Zigbee protocols are intended for embedded applications requiring low data rates and low power consumption, and are now being implemented into everyday home appliances which can allow for further home area network communications, as well as a cornerstone for “smart grid” application development.

e. Is HCHI aware there is a smart grid working committee that is looking into standards for smart grid communications?

HCHI Response

Yes, HCHI is aware of such a working committee, the OEB Smart Grid Advisory Committee (EB-2013-0294).

f. Please state any authorization that HCHI has to proceed with expenditures to implement ZigBee.

HCHI Response

HCHI has proceeded to implement Zigbee communication technology as per the OPA residential and general service less than 50kW class demand response program (PeakSaver) which requires the participant to have an IHD to better understand electricity usage patterns. HCHI is mandated by the OEB as part of its Distribution Licence to meet energy and demand targets for CDM programs. HCHI has opted to deliver all OPA programs.

Has HCHI reviewed the Board's findings in Guelph Hydro Inc. (EB-2011-0123) in which it disallowed a Zigbee-based proposal? If so, please state any differences in HCHI's ZigBee proposal from that of Guelph Hydro Inc.'s, and why HCHI's proposal should not be disallowed.

HCHI Response

HCHI's proposal should not be disallowed as its smart meter implementation strategy is not the same. Guelph Hydro opted to deploy all of their smart meter population with Zigbee technology where HCHI did not. HCHI feels strongly that to stay current with energy and demand savings opportunities today and in the near future, technology considerations need to be embraced. It should also be noted that the incremental cost of Zigbee for the purpose of the PeakSaver program is covered by the OPA's PeakSaver Plus program.

HCHI is not planning to change out all of its smart meter inventory. HCHI will be targeting areas within its distribution territory for Zigbee-enabled smart meters where conservation program uptake is happening or probable (i.e. new service installations). For example, the cost of Zigbee communication installation is significantly less when implemented for new service installations due to the fact that no further truck rolls and/or man hours are required in future if Zigbee is required. HCHI intends to target new installs with Zigbee-enabled meters, as these are most likely to include new residential builds, where the customers are potentially more intrigued to participate in energy conservation programs.

HCHI states that over 4% of its customers have participated in the peaksaver programme:

g. What is HCHI's estimate of the capital costs of not reducing peak demand as planned?

HCHI Response

HCHI has no estimate of the capital costs.

h. From a planning and cost perspective, what are the benefits of an avoided peak if HCHI's customers participated in the program at average provincial rates?

HCHI Response

HCHI has no analysis of the avoided peak costs.

5.1 EP 9.

Reference: Current Application

a. **Please provide a list of the obligations mandated by government in 2010 through to the current time.**

HCHI Response

Obligations mandated by government either in 2009 or 2010 and continuing through to current time for which HCHI has or is continuing to meet, include, but are not limited to, the following:

- The Green Energy and Green Economy Act, 2009 (the "GEA") and related Regulations:
    - Feed-in Tariff ("FIT") regime and role of Ontario Power Authority (the "OPA") – replacing former RESOP;
    - Facilitating renewable energy;
        - Distribution and Transmission-connected generators, including the process for connecting and connection cost responsibilities and connection charges;
        - Regulatory treatment of infrastructure investments;
        - Metering, settlement and billing; and
        - Rate protection and determination of direct benefits.
    - Conservation and Demand Management Targets;
        - Provincial targets set by the Minister of Energy and LDC-specific targets, as set by the OEB, as a condition of HCHI's Distribution Licence;
        - Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA").
    - Development of a Smart Grid.
- Smart Meter deployment, including the Advanced Metering Infrastructure ("AMI") and mandated Time-of-Use ("TOU") pricing;

Operational Data Store ("ODS"); Smart Meter Entity charges; and Communications.

- ESA Regulation 22/04 – in 2012/2013, HCHI has received a 'clean' audit with respect to ESA Regulation 22/04 compliance. HCHI also completes two Due Diligence Inspections annually with ESA Inspectors.
- Distribution System Code amendments, including:
    - Stray Voltage, for which equipment and training have been purchased for technicians to perform testing;
    - The elimination of long term load transfer customers;
    - Revised customer service rules related to the provision of service and application of charges, including security deposits and arrears management; and
    - Energy issues related to low income energy consumers and the Low Income Energy Assistance Program ("LEAP").
- Ontario Clean Energy Benefit ("OCEB").
- Ontario One-Call.
- International Financial Reporting Standards ("IFRS") with respect to capitalization policy on useful lives.

b. For each of the obligations noted in (a) above, please explain how the distributor has met those obligations.

<u>HCHI Response</u>

Refer to response in a; that is, for each obligation noted, HCHI has met, or is continuing to meet those obligations as demonstrated in its original evidence and in its collective responses to these interrogatories.

5.1 VECC 20.

Reference: ALL

Please provide HCHI's estimate of the ongoing cost in 2014 of meeting all new government and OEB obligations established since 2010. Please categorize each requirement.

<u>HCHI Response</u>

Please refer to response to EP IR # 9, which provides a list of the government obligations that HCHI has met and continues to meet since 2010. Meeting each of these obligations may include the requirement for technical, metering, customer service, financial settlement, accounting and regulatory reporting aspects; that is, across all departments and various OM&A accounts. Accordingly, it is hard to estimate the ongoing cost in 2014 of meeting these obligations; however, in part, reference should be made to responses to previous interrogatories regarding the rationale for staffing levels, OM&A outcomes and operational efficiencies, including Staff IR # 11, 12, 15 and 17.

6 Financial Performance

6.1 Do the applicant's proposed rates allow it to meet its obligations to its customers while maintaining its financial viability?

6.1 VECC 21.

Reference: E1/T1/S1

Please provide the following inflation information for the period 2010 through 2013:

a. CPI (Statistics Canada);

<u>HCHI Response</u>

CPI (Ontario) – yearly annual average:

- 2013 – 1.2%
- 2012 – 1.7%
- 2011 – 3.6%
- 2010 – 2.8%

b. GDPI;

<u>HCHI Response</u>

GDP-IPI (OEB)

- 2013 – 1.6%
- 2012 – 2.0%
- 2011 – 1.3%
- 2010 – 1.3%

c. HCHI's 2010-2014 IRM productivity factor, and

<u>HCHI Response</u>

- 2013 – 0.72%
- 2012 – 0.72%
- 2011 – 0.72%
- 2010 – Cost of Service

d. **HCHI's 2010 – 2014 Stretch Factor.**

<u>HCHI Response</u>

Refer to response to EP IR # 4.

6.2 Has the applicant adequately demonstrated that the savings resulting from its operational effectiveness initiatives are sustainable?

6.2 EP 10.

Reference: Exhibits 1, 2 & 4

a. Please describe, with references to the evidence, the operational effectiveness initiatives that the distributor has or is planning to undertake.

HCHI Response

See Staff IR # 12 c. for a description of "operational effectiveness initiatives". Where cost avoidance or savings are known they are described.

b. Please show now these initiatives have, or will, result in savings to ratepayers.

HCHI Response

See response to Staff IR # 12 c. for a description of "operational effectiveness initiatives". Where cost avoidance or savings are known they are described.

c. Please explain how the savings identified in part (b) above are sustainable.

HCHI Response

Refer also to response to Staff IR # 12 c.

Lump Sum Construction Tenders and Lump Sum Tree Trimming – This will continue to be sustainable as long as HCHI follows this practice. Savings are based on market conditions.

Tree Trimming Hold Off Credit – This savings is sustainable as long as HCHI allows the practice to continue and qualified bidders are awarded the contracts.

Loss Reduction – This will be sustainable as HCHI continues to install and design projects with a focus on loss reduction improvement.

Prior Year Engineering Designs – This program will be sustainable as HCHI realizes the benefits of designing in one year and constructing in the next to ensure cost certainty and efficiency.

Banner Installation – HCHI no longer installs banners, so this is sustainable pending a change in direction by HCHI's Board of Directors to resume this program.

Ontario "One-Call" Locates – HCHI has eliminated subcontractors who used to deliver locate services and meter services.

Autodialer – HCHI has eliminated printing and postage costs and will not return to paper based collection notices.

6.2 VECC 22.

Reference: All

Please identify all "operational effectiveness initiatives" undertaken since 2010 and the annual savings each initiative has and will result in in 2014.

<u>HCHI Response</u>

See response to Staff IR # 12 c. for a description of "operational effectiveness initiatives". Where cost avoidance or savings are known they are described.

6.2 VECC 23.

Reference: E4/T2/S4/Table 7

How many of the 2014 forecast 60 FTEs positions are currently unfilled?

<u>HCHI Response</u>

Only one of the 60 FTE positions is currently unfilled. One of the new positions was filled by the end of 2013 as explained in Exhibit 4 / Tab 2 / Schedule 4 / Page 7.

6.2 VECC 24.

Reference: E4/T4/S2/Table 7

The purpose of this interrogatory is to try to match incremental Utility responsibilities to the incremental increase in FTEs

a. **Please separate the 2012 to 2014 incremental staff increase of 6 FTEs into the following categories:**

   - **i) Related to incremental Smart Meter/TOU billing activities;**
   - **ii) Related to incremental regulatory and government mandated policy requirements (except CDM)**
   - **iii) Primarily related to customer growth (e.g. customer service, line crew);**
   - **iv) Primarily related to enhanced system maintenance, reliability or safety (e.g. GIS, SCADA, etc.);**
   - **v) Primarily related to governance (e.g. finance, HR, planning, etc.);**
   - **vi) Temporary backfilled position / training for an expected retirement;**

   HCHI Response

   HCHI's FTEs only increased by 2 from 2012 Actuals (58 FTEs) to 2014 Test Year (60 FTEs). These 2 positions include a Meter Technician and a Lineperson – Apprentice. Both of these positions can be attributed to one respect or another of each of the categories (i) through (v) described above.

b. **Please provide a dollar estimate for each category.**

   HCHI Response

   HCHI does not have the detailed information, aggregated by VECC's categories, in order to provide a response.

7 Revenue Requirement

7.1 Is the proposed Test year rate base including the working capital allowance reasonable?

7.1 EP 11.

Reference: Exhibit 2, Tab 2, Schedule 1

a. Please explain why there is a disposal from accumulated depreciation shown in Table 10 for 2010 in account 1611, but there is no associated disposal shown from costs.

HCHI Response

In Table 10 of Exhibit 2 / Tab 2 / Schedule 1, the disposal of $164,220 in accumulated depreciation should be associated with account 1930 Transportation Equipment; the row below account 1611. This presentation does not impact the revenue requirement calculations.

b. Please explain why there is a disposal from costs shown in Table 10 for 2010 in account 1930, but there is no associated disposal shown from accumulated depreciation.

HCHI Response

Refer to response in a.

c. **Please reconcile the smart meter additions to costs and accumulated depreciation shown for 2012 in Table 12, with the figures noted on page 4 of Exhibit 2 / Tab 1 / Schedule 2. Is the difference all related to the addition of smart meters in 2012 after the smart meter decision?**

HCHI Response

Smart Meter capital additions for the year 2012 are detailed as follows:

Smart Meter Capital Additions – 2012 Actual

2012 Fixed Asset Continuity Schedule	Smart Meter Approved Disposition	Difference
$ 3,724,761	$ 3,682,120	$ 42,641

The difference of $42,641 is on account of additional smart meters installed in 2012 recorded directly to account 1860 and not included in the smart meter disposition of deferral account 1555.

7.1 EP 12.

Reference: Exhibit 2, Tab 2, Schedule 1 &
Exhibit 9, Tab 4, Schedule 1

a. **Please provide an updated version of Tables 13 and 14 that reflect actual data for 2013. If actual data is not yet available for all of 2013, please provide revised tables that reflect the most recent year-to-date information available, along with an estimate/forecast for the remainder of 2013.**

HCHI Response

The following Tables 13 and 14 provide updated information to include the 2013 actual data (internally prepared and unaudited) for the Fixed Asset Continuity Schedule pre- and post-accounting change to useful lives.

Table 13
Fixed Asset Continuity Schedule
As at December 31, 2013
(Pre-Accounting Change to Useful Lives)

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
CEC	1609	Distribution Station Equipment <50 kV - Capital Contribution Paid	$ -	$ 29,835		$ 29,835	$ -	$ -		$ -	$ 29,835
47	1820	Distribution Station Equipment <50 kV	$ 466,497			$ 466,497	$ (185,350)	(17,266)		$ (202,616)	$ 263,881
47	1830	Poles, Towers & Fixtures	$ 20,627,452	1,441,178	$ (30,466)	$ 22,038,164	$ (9,325,608)	(986,083)	$ 30,409	$ (10,281,282)	$ 11,756,882
47	1835	Overhead Conductors & Devices	$ 13,556,975	742,157		$ 14,299,132	$ (4,174,410)	(601,929)		$ (4,776,339)	$ 9,522,793
47	1840	Underground Conduit	$ 1,366,196	466,277		$ 1,832,473	$ (147,380)	(65,675)		$ (213,055)	$ 1,619,418
47	1845	Underground Conductors & Devices	$ 7,702,253	1,006,024		$ 8,708,277	$ (3,666,462)	(341,852)		$ (4,008,314)	$ 4,699,963
47	1850	Line Transformers	$ 12,387,905	751,409		$ 13,139,314	$ (4,738,267)	(517,158)		$ (5,255,425)	$ 7,883,889
47	1855	Services (Overhead & Underground)	$ 2,683,092	328,565		$ 3,011,657	$ (830,444)	(114,508)		$ (944,952)	$ 2,066,705
47	1860	Meters	$ 3,034,121	91,080	(1,666,572)	$ 1,458,629	$ (1,313,129)	(123,701)	1,182,640	$ (254,190)	$ 1,204,439
47	1860	Smart Meters	$ 3,724,762	58,585		$ 3,783,347	$ (757,661)	(244,730)		$ (1,002,391)	$ 2,780,956
N/A	1905	Land	$ 127,139			$ 127,139				$ -	$ 127,139
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (259,892)	(20,721)		$ (280,613)	$ 414,776
1 b	1908	Buildings & Fixtures	$ 2,190,518	1,450		$ 2,191,968	$ (467,768)	(51,546)		$ (519,314)	$ 1,672,654
8	1915	Office Furniture & Equipment (10 years)	$ 365,636	13,200	(1,023)	$ 377,813	$ (261,240)	(22,925)	1,023	$ (283,142)	$ 94,671
50	1920	Computer Equipment - Hardware	$ 585,095	48,670		$ 633,765	$ (395,997)	(70,069)		$ (466,066)	$ 167,699
50	1611	Computer Software (Formally known as Account 1925)	$ 2,765,069	96,016		$ 2,861,085	$ (2,101,504)	(325,465)		$ (2,426,969)	$ 434,116
10	1930	Transportation Equipment	$ 2,207,646	260,503	(50,273)	$ 2,417,876	$ (1,183,300)	(207,032)	50,273	$ (1,340,059)	$ 1,077,817
8	1940	Tools, Shop & Garage Equipment	$ 795,038	38,146		$ 833,184	$ (451,778)	(57,045)		$ (508,823)	$ 324,361
8	1955	Communications Equipment	$ 68,074			$ 68,074	$ (57,942)	(3,863)		$ (61,805)	$ 6,269
47	1995	Contributions & Grants	$ (4,143,672)	(1,039,446)		$ (5,183,118)	$ 1,007,443	182,818		$ 1,190,261	$ (3,992,857)
	etc.										
		Sub-Total	$ 71,205,185	$ 4,333,649	$ (1,748,334)	$ 73,790,500	$ (29,310,689)	$ (3,588,750)	$ 1,264,345	$ (31,635,094)	$ 42,155,406
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 71,205,185	$ 4,333,649	$ (1,748,334)	$ 73,790,500	$ (29,310,689)	$ (3,588,750)	$ 1,264,345	$ (31,635,094)	$ 42,155,406

Less: CDM-OPA Allocated Costs - Depreciation Expense	
Building	$ 855
Office Equipment	$ 380
Computer Hardware	$ 1,163
Computer Software	$ 1,036
Net Depreciation Expense	$ (3,585,316)

Table 14
Fixed Asset Continuity Schedule
As at December 31, 2013
(Post-Accounting Change to Useful Lives)

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
CEC	1609	Distribution Station Equipment <50 kV - Capital Contribution Paid	$ -	29,835		$ 29,835	$ -	$ -		$ -	$ 29,835
47	1820	Distribution Station Equipment <50 kV	$ 466,497			$ 466,497	$ (185,350)	(8,031)		$ (193,381)	$ 273,116
47	1830	Poles, Towers & Fixtures - Wood Poles	$ 20,543,025	1,441,178	$ (30,466)	$ 21,953,737	$ (9,281,040)	(277,556)	$ 30,409	$ (9,528,187)	$ 12,425,550
47	1830	Poles, Towers & Fixtures - Metal/Concrete Poles	$ 84,427			$ 84,427	$ (44,568)	(834)		$ (45,402)	$ 39,025
47	1835	Overhead Conductors & Devices - Conductor	$ 12,599,263	742,157		$ 13,341,420	$ (3,718,103)	(204,558)		$ (3,922,661)	$ 9,418,759
47	1835	Overhead Conductors & Devices - Switches	$ 510,902			$ 510,902	$ (273,141)	(7,255)		$ (280,396)	$ 230,506
47	1835	Overhead Conductors & Devices - Reclosures	$ 446,811			$ 446,811	$ (183,166)	(8,441)		$ (191,607)	$ 255,204
47	1840	Underground Conduit - Duct	$ 1,366,196	466,277		$ 1,832,473	$ (147,380)	(28,910)		$ (176,290)	$ 1,656,183
47	1845	Underground Conductors & Devices - Cable (Non-Duct)	$ 6,219,026	17,894		$ 6,236,920	$ (2,961,123)	(172,435)		$ (3,133,558)	$ 3,103,362
47	1845	Underground Conductors & Devices - Cable (In Duct)	$ 1,428,183	963,360		$ 2,391,543	$ (682,394)	(29,162)		$ (711,556)	$ 1,679,987
47	1845	Underground Conductors & Devices - Switchgear	$ 55,043	24,770		$ 79,813	$ (22,945)	(2,164)		$ (25,109)	$ 54,704
47	1850	Line Transformers - Pole Top	$ 9,439,683	431,525		$ 9,871,208	$ (3,943,726)	(186,850)		$ (4,130,576)	$ 5,740,632
47	1850	Line Transformers - Padmount	$ 2,420,047	255,442		$ 2,675,489	$ (703,172)	(50,828)		$ (754,000)	$ 1,921,489
47	1850	Line Transformers - Step-Down (Rabbits)	$ 314,345			$ 314,345	$ (91,369)	(6,590)		$ (97,959)	$ 216,386
47	1850	Line Transformers - Spare Capital	$ 213,830	64,442		$ 278,272	$ -			$ -	$ 278,272
47	1855	Services - Overhead	$ 984,278	83,868		$ 1,068,146	$ (294,207)	(13,586)		$ (307,793)	$ 760,353
47	1855	Services - Underground	$ 1,698,814	244,697		$ 1,943,511	$ (536,237)	(44,587)		$ (580,824)	$ 1,362,687
47	1860	Meters - Primary Metering Units	$ 129,969	17,145		$ 147,114	$ (22,207)	(6,667)		$ (28,874)	$ 118,240
47	1860	Meters - Interval Meters & Other Metering Equipment	$ 1,142,904	779		$ 1,143,683	$ (150,783)	(217,520)		$ (368,303)	$ 775,380
47	1860	Meters - Smart Meters	$ 3,724,762	58,585		$ 3,783,347	$ (757,661)	(244,730)		$ (1,002,391)	$ 2,780,956
47	1860	Meters - Stranded Conventional Meters	$ 1,666,572		(1,666,572)	$ -	$ (1,140,139)	(42,501)	1,182,640	$ -	$ -
47	1860	Meters - Spare Capital	$ 94,676	73,156		$ 167,832	$ -			$ -	$ 167,832
N/A	1905	Land	$ 127,139			$ 127,139				$ -	$ 127,139
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (259,892)	(20,721)		$ (280,613)	$ 414,776
1 b	1908	Buildings & Fixtures	$ 2,190,518	1,450		$ 2,191,968	$ (467,768)	(51,546)		$ (519,314)	$ 1,672,654
8	1915	Office Furniture & Equipment (10 years)	$ 365,636	13,200	(1,023)	$ 377,813	$ (261,240)	(22,925)	1,023	$ (283,142)	$ 94,671
50	1920	Computer Equipment - Hardware	$ 585,095	48,670		$ 633,765	$ (395,997)	(70,069)		$ (466,066)	$ 167,699
50	1611	Computer Software (Formally known as Account 1925)	$ 2,765,069	96,016		$ 2,861,085	$ (2,101,504)	(325,465)		$ (2,426,969)	$ 434,116
10	1930	Transportation Equipment - Bucket Trucks	$ 1,759,603	225,418	(50,273)	$ 1,934,748	$ (904,828)	(97,766)	50,273	$ (952,321)	$ 982,427
10	1930	Transportation Equipment - Pickups and Vans	$ 364,206	35,085		$ 399,291	$ (227,321)	(40,143)		$ (267,464)	$ 131,827
10	1930	Transportation Equipment - Trailers	$ 83,837			$ 83,837	$ (51,151)	(1,999)		$ (53,150)	$ 30,687
8	1940	Tools, Shop & Garage Equipment	$ 795,038	38,146		$ 833,184	$ (451,778)	(57,045)		$ (508,823)	$ 324,361
8	1955	Communications Equipment	$ 68,074			$ 68,074	$ (57,942)	(3,863)		$ (61,805)	$ 6,269
47	1995	Contributions & Grants - Wood Poles	$ (739,792)	(105,320)		$ (845,112)	$ 184,802	14,559		$ 199,361	$ (645,751)
47	1995	Contributions & Grants - Metal / Concrete Poles	$ -			$ -	$ -	0		$ -	$ -
47	1995	Contributions & Grants - O/H Conductor	$ (206,948)	(10,730)		$ (217,678)	$ 39,943	3,727		$ 43,670	$ (174,008)
47	1995	Contributions & Grants - O/H Line Switches	$ (8,391)	(34)		$ (8,425)	$ 1,722	169		$ 1,891	$ (6,534)
47	1995	Contributions & Grants - O/H Reclosures	$ (7,345)	(39)		$ (7,384)	$ 1,507	170		$ 1,677	$ (5,707)
47	1995	Contributions & Grants - U/G Conduit	$ (303,943)	(60,918)		$ (364,861)	$ 66,336	5,761		$ 72,097	$ (292,764)
47	1995	Contributions & Grants - U/G Conductor (Non-Duct)	$ (1,081,893)	(45,961)		$ (1,127,854)	$ 263,019	35,422		$ 298,441	$ (829,413)
47	1995	Contributions & Grants - U/G Conductor (In Duct)	$ (242,982)	(560,093)		$ (803,075)	$ 59,071	9,483		$ 68,554	$ (734,521)
47	1995	Contributions & Grants - Pole Top Transformers	$ (668,018)	(57,039)		$ (725,057)	$ 179,942	15,045		$ 194,987	$ (530,070)
47	1995	Contributions & Grants - Padmount Transformers	$ (171,269)	(181,146)		$ (352,415)	$ 46,091	4,204		$ 50,295	$ (302,120)
47	1995	Contributions & Grants - Step-Down Transformers	$ (22,227)	(1,194)		$ (23,421)	$ 5,982	499		$ 6,481	$ (16,940)
47	1995	Contributions & Grants - O/H Services	$ (149,478)	(1,138)		$ (150,616)	$ 40,101	2,063		$ 42,164	$ (108,452)
47	1995	Contributions & Grants - U/G Services	$ (258,042)	(1,351)		$ (259,393)	$ 69,225	3,561		$ 72,786	$ (186,607)
47	1995	Contributions & Grants - Primary Metering Units	$ (156,852)			$ (156,852)	$ 21,959	8,431		$ 30,390	$ (126,462)
47	1995	Contributions & Grants - Intervals & Other Metering Equipment	$ (28,461)	(3,164)		$ (31,625)	$ 6,242	2,835		$ 9,077	$ (22,548)
47	1995	Contributions & Grants - Smart Meters	$ (98,031)	(11,319)		$ (109,350)	$ 21,501	9,768		$ 31,269	$ (78,081)
	etc.										
		Sub-Total	$ 71,205,185	$ 4,333,649	$ (1,748,334)	$ 73,790,500	$ (29,310,689)	$ (2,129,050)	$ 1,264,345	$ (30,175,394)	$ 43,615,106
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 71,205,185	$ 4,333,649	$ (1,748,334)	$ 73,790,500	$ (29,310,689)	$ (2,129,050)	$ 1,264,345	$ (30,175,394)	$ 43,615,106

Less: CDM-OPA Allocated Costs - Depreciation Expense	
Building	$ 855
Office Equipment	$ 380
Computer Hardware	$ 1,163
Computer Software	$ 1,036
Net Depreciation Expense	$ (2,125,616)

b. Please provide an updated version of Table 15 for the 2014 test year to reflect the new opening balances brought forward from Table 14.

HCHI Response

The following Table 15 provides updated information inclusive of the 2013 actual data (internally prepared and unaudited) in the opening balances brought forward into the 2014 Test Year Fixed Asset Continuity Schedule.

Table 15
Fixed Asset Continuity Schedule
As at December 31, 2014

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
CEC	1609	Distribution Station Equipment <50 kV - Capital Contribution Paid	$ 29,835	441,675		$ 471,510	$ -	$ (5,571)		$ (5,571)	$ 465,939
47	1820	Distribution Station Equipment <50 kV	$ 466,497	5,000		$ 471,497	$ (193,381)	(8,091)		$ (201,472)	$ 270,025
47	1830	Poles, Towers & Fixtures - Wood Poles	$ 21,953,737	2,219,344		$ 24,173,081	$ (9,528,187)	(319,541)		$ (9,847,728)	$ 14,325,353
47	1830	Poles, Towers & Fixtures - Metal/Concrete Poles	$ 84,427			$ 84,427	$ (45,402)	(835)		$ (46,237)	$ 38,190
47	1835	Overhead Conductors & Devices - Conductor	$ 13,341,420	1,446,682		$ 14,788,102	$ (3,922,661)	(227,574)		$ (4,150,235)	$ 10,637,867
47	1835	Overhead Conductors & Devices - Switches	$ 510,902	15,900		$ 526,802	$ (280,396)	(7,437)		$ (287,833)	$ 238,969
47	1835	Overhead Conductors & Devices - Reclosures	$ 446,811			$ 446,811	$ (191,607)	(8,446)		$ (200,053)	$ 246,758
47	1840	Underground Conduit - Duct	$ 1,832,473	660,890		$ 2,493,363	$ (176,290)	(41,490)		$ (217,780)	$ 2,275,583
47	1845	Underground Conductors & Devices - Cable (Non-Duct)	$ 6,236,920			$ 6,236,920	$ (3,133,558)	(174,008)		$ (3,307,566)	$ 2,929,354
47	1845	Underground Conductors & Devices - Cable (In Duct)	$ 2,391,543	588,165		$ 2,979,708	$ (711,556)	(56,879)		$ (768,435)	$ 2,211,273
47	1845	Underground Conductors & Devices - Switchgear	$ 79,813	41,600		$ 121,413	$ (25,109)	(3,158)		$ (28,267)	$ 93,146
47	1850	Line Transformers - Pole Top	$ 9,871,208	620,312		$ 10,491,520	$ (4,130,576)	(199,856)		$ (4,330,432)	$ 6,161,088
47	1850	Line Transformers - Padmount	$ 2,675,489	178,699		$ 2,854,188	$ (754,000)	(59,837)		$ (813,837)	$ 2,040,351
47	1850	Line Transformers - Step-Down (Rabbits)	$ 314,345	69,828		$ 384,173	$ (97,959)	(7,525)		$ (105,484)	$ 278,689
47	1850	Line Transformers - Spare Capital	$ 278,272			$ 278,272	$ -			$ -	$ 278,272
47	1855	Services - Overhead	$ 1,068,146	113,572		$ 1,181,718	$ (307,793)	(15,354)		$ (323,147)	$ 858,571
47	1855	Services - Underground	$ 1,943,511	136,725		$ 2,080,236	$ (580,824)	(51,426)		$ (632,250)	$ 1,447,986
47	1860	Meters - Primary Metering Units	$ 147,114	87,436		$ 234,550	$ (28,874)	(9,642)		$ (38,516)	$ 196,034
47	1860	Meters - Interval Meters & Other Metering Equipment	$ 1,143,683	34,660		$ 1,178,343	$ (368,303)	(191,525)		$ (559,828)	$ 618,515
47	1860	Meters - Smart Meters	$ 3,783,347	133,025		$ 3,916,372	$ (1,002,391)	(249,381)		$ (1,251,772)	$ 2,664,600
47	1860	Meters - Stranded Conventional Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters - Spare Capital	$ 167,832			$ 167,832	$ -			$ -	$ 167,832
N/A	1905	Land	$ 127,139			$ 127,139	$ -			$ -	$ 127,139
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (280,613)	(20,720)		$ (301,333)	$ 394,056
1 b	1908	Buildings & Fixtures	$ 2,191,968			$ 2,191,968	$ (519,314)	(51,730)		$ (571,044)	$ 1,620,924
8	1915	Office Furniture & Equipment (10 years)	$ 377,813	5,000		$ 382,813	$ (283,142)	(22,864)		$ (306,006)	$ 76,807
50	1920	Computer Equipment - Hardware	$ 633,765	109,344		$ 743,109	$ (466,066)	(64,095)		$ (530,161)	$ 212,948
50	1611	Computer Software (Formally known as Account 1925)	$ 2,861,085	280,645		$ 3,141,730	$ (2,426,969)	(201,295)		$ (2,628,264)	$ 513,466
10	1930	Transportation Equipment - Bucket Trucks	$ 1,934,748			$ 1,934,748	$ (952,321)	(107,393)		$ (1,059,714)	$ 875,034
10	1930	Transportation Equipment - Pickups and Vans	$ 399,291	218,400		$ 617,691	$ (267,464)	(54,522)		$ (321,986)	$ 295,705
10	1930	Transportation Equipment - Trailers	$ 83,837			$ 83,837	$ (53,150)	(2,000)		$ (55,150)	$ 28,687
8	1940	Tools, Shop & Garage Equipment	$ 833,184	67,250		$ 900,434	$ (508,823)	(56,846)		$ (565,669)	$ 334,765
8	1955	Communications Equipment	$ 68,074			$ 68,074	$ (61,805)	(3,861)		$ (65,666)	$ 2,408
47	1995	Contributions & Grants - Wood Poles	$ (845,112)	(38,153)		$ (883,265)	$ 199,361	15,135		$ 214,496	$ (668,769)
47	1995	Contributions & Grants - Metal / Concrete Poles	$ -			$ -	$ -	0		$ -	$ -
47	1995	Contributions & Grants - O/H Conductor	$ (217,678)	(5,254)		$ (222,932)	$ 43,670	3,973		$ 47,643	$ (175,289)
47	1995	Contributions & Grants - O/H Line Switches	$ (8,425)			$ (8,425)	$ 1,891	167		$ 2,058	$ (6,367)
47	1995	Contributions & Grants - O/H Reclosures	$ (7,384)			$ (7,384)	$ 1,677	168		$ 1,845	$ (5,539)
47	1995	Contributions & Grants - U/G Conduit	$ (364,861)	(16,303)		$ (381,164)	$ 72,097	6,712		$ 78,809	$ (302,355)
47	1995	Contributions & Grants - U/G Conductor (Non-Duct)	$ (1,127,854)			$ (1,127,854)	$ 298,441	36,234		$ 334,675	$ (793,179)
47	1995	Contributions & Grants - U/G Conductor (In Duct)	$ (803,075)	(166,761)		$ (969,836)	$ 68,554	21,545		$ 90,099	$ (879,737)
47	1995	Contributions & Grants - Pole Top Transformers	$ (725,057)	(31,658)		$ (756,715)	$ 194,987	16,535		$ 211,522	$ (545,193)
47	1995	Contributions & Grants - Padmount Transformers	$ (352,415)	(44,297)		$ (396,712)	$ 50,295	8,856		$ 59,151	$ (337,561)
47	1995	Contributions & Grants - Step-Down Transformers	$ (23,421)			$ (23,421)	$ 6,481	520		$ 7,001	$ (16,420)
47	1995	Contributions & Grants - O/H Services	$ (150,616)	(19,639)		$ (170,255)	$ 42,164	2,238		$ 44,402	$ (125,853)
47	1995	Contributions & Grants - U/G Services	$ (259,393)	(24,179)		$ (283,572)	$ 72,786	7,102		$ 79,888	$ (203,684)
47	1995	Contributions & Grants - Primary Metering Units	$ (156,852)			$ (156,852)	$ 30,390	8,431		$ 38,821	$ (118,031)
47	1995	Contributions & Grants - Intervals & Other Metering Equipment	$ (31,625)	(1,672)		$ (33,297)	$ 9,077	3,009		$ 12,086	$ (21,211)
47	1995	Contributions & Grants - Smart Meters	$ (109,350)	(6,149)		$ (115,499)	$ 31,269	10,404		$ 41,673	$ (73,826)
	etc.										
		Sub-Total	$ 73,790,500	$ 7,120,087	$ -	$ 80,910,587	$ (30,175,394)	$ (2,081,873)	$ -	$ (32,257,267)	$ 48,653,320
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 73,790,500	$ 7,120,087	$ -	$ 80,910,587	$ (30,175,394)	$ (2,081,873)	$ -	$ (32,257,267)	$ 48,653,320

Less: CDM-OPA Allocated Costs - Depreciation Expense	
Building	$ 916
Office Equipment	$ 405
Computer Hardware	$ 1,134
Computer Software	$ 1,227
Net Depreciation Expense	$ (2,078,191)

c. Please provide an updated version of Table 18 in Exhibit 9, Tab 4, Schedule 1 based on the revised Tables 13 and 14 requested in part (a) above, along with the change in the cost of capital parameters as requested in 7.5-Energy Probe-22 and 7.4-Energy Probe-23.

<u>HCHI Response</u>

HCHI has updated the accounting change to be recorded in account 1576 based on its responses to EP IR # 22 and # 23, and this IR part a.

Table 18
Account 1576 – Accounting Changes under CGAAP

	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Actual	Forecast				
	$	$	$	$	$	$
PP&E Values under former CGAAP						
Opening net PP&E	41,894,496					
Net Additions	2,585,315					
Net Depreciation (amounts should be negative)	(2,324,405)					
Closing net PP&E	42,155,406					
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E	41,894,496					
Net Additions	2,585,315					
Net Depreciation (amounts should be negative)	(864,705)					
Closing net PP&E	43,615,106					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP	(1,459,700)					
Effect on Deferral and Variance Account Rate Riders						
Closing balance in Account 1576		(1,459,700)		WACC	5.45%	
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2		(397,768)				
Amount included in Deferral and Variance Account Rate Rider Calculation		(1,857,468)		# of years of rate rider disposition period	5	

7.1 EP 13.

Reference: Exhibit 2, Tab 2, Schedule 1

Please explain the following reductions in the contributions and grants between 2013 (Table 14) and 2014 (Table 15) despite cost additions being higher in 2014 than in 2013:

i) wood poles - $50,000;
ii) u/g conduit - $100,000;
iii) u/g conduction (in duct) - $143,249; and
iv) padmount transformers - $34,490.

<u>HCHI Response</u>

The capital cost of additions is not linear to the capital cost of contributions and grants; that is, the majority of the capital additions are not offset by a capital contribution.

7.1 EP 14. (Jackie / Sherry)

Reference: Exhibit 2, Tab 2, Schedule 1

Please confirm that HCHI does not have any fully allocated depreciation expense (such as for transportation equipment) that it allocates to capital projects and OM&A expenses. If this cannot be confirmed, please show where this amount is shown in Table 15 and indicate the amount capitalized and the amount expensed.

HCHI Response

Confirmed.

7.1 EP 15.

Reference: Exhibit 2, Tab 2, Schedule 1

The depreciation expense for 2014 shown in Table 15 has been reduced by $3,969 for CDM-OPA allocated costs.

Please show the calculation of each of the four amounts in a table similar to Table 15 that shows the opening balances (cost and accumulated depreciation), additions, disposals, the resulting closing balances and net book value of the portion of the assets that give rise to the depreciation expenses allocated to CDM-OPA.

<u>HCHI Response</u>

HCHI notes that the depreciation expense of $3,969 allocated to CDM-OPA costs is well below HCHI's materiality threshold of $64,000. The Board's Procedural Order No. 2 reminded parties to take into consideration this materiality threshold when engaging in detailed exploration of items. However, HCHI is providing its calculations of the four depreciation amounts allocated to CDM-OPA costs in the table below.

CDM-OPA Allocated Cost Calculation – 2014 Test Year

Asset Category	Depreciation Expense	Indirect Cost % Allocation	CDM-OPA Allocated Costs
Building	$ 51,730	1.77%	$ 916
Office Equipment	22,864	1.77%	405
Computer Hardware	64,095	1.77%	1,134
Computer Software	69,349	1.77%	1,227
Total	$ 208,038		$ 3,682

Notes:
1. Computer Software Depreciation Expense does not include the asset depreciation of the CIS Conversion project and the ESRI Mapping System
2. Indirect Cost % Allocation is calculated based on the Conservation Specialist labour costs to the total company labour costs.

7.1 EP 16.

Reference: Exhibit 2, Tab 2, Schedule 1

When did/will the asset for which HCHI is paying HONI a capital contribution (account 1609 in Tables 14 and 15) go into service?

<u>HCHI Response</u>

The capital contribution that HCHI is paying HONI in 2013 and 2014 is for an additional breaker position at Dunnville TS. HONI has an expected in-service date of June 2015 for the new transformer station. This will also be the in-service date for the new breaker position.

7.1 VECC 25.

Reference: E2/T3/S1 & E4/T2/S1

Are all customer classes billed on a monthly cycle? Has there been any change in billing cycles to any class since 2010?

Response

HCHI bills all customers monthly and there has been no change in billing cycle to any class since 2010.

7.2 Are the proposed levels of depreciation/amortization expense appropriately reflective of the useful lives of the assets and the Board`s accounting policies?

7.2 Staff 25. Depreciation

Reference: Appendix 2-CU

HCHI has established depreciation rates based on individual asset type expected lives. However, some assets form asset groups. In Asset groups, all assets collectively provide a unique distribution function. As such, they generally will all be retired at the same time. As an example of Board staff's view, Poles, towers & fixtures ("Poles"), overhead conductors and devices ("Conductors") are being planned to be replaced at the same time. Poles support conductors. While physically poles may last longer than conductors, as a group, they only have value to the customer over their economic or useful life. HCHI is proposing 60 year asset lives for concrete poles, 45 years for line switches, 40 years for reclosers and 50 years for conductors. Board staff is interested in HCHI's view on depreciation of those assets which are installed and retired as a group at the same time.

a. Please provide an explanation for the proposed depreciation of the individual assets that form groups,

<u>HCHI Response</u>

In determining its useful lives for asset categories, components and types, HCHI was assisted by the generic depreciation study report prepared by Kinectrics Inc., dated July 8, 2010, entitled "*Asset Depreciation Study for the Ontario Energy Board*" (the "Kinectrics Report"). While HCHI adopted many of the typical useful life ("TUL") results suggested in Table F of the Kinectrics Report, it also selected the level of componentization and depreciation periods based on its specific experience.

HCHI determined that reclosers and line switches are individual devices, typically installed on single poles that can be installed or removed separately from the asset type of poles and conductors. HCHI has previously relocated in-service line switches and reclosers within its system in order to improve operations as the system evolves. If poles and conductor were being removed at end of life, and based upon HCHI's examination of a specific recloser or gang operated overhead line switch to be in good operating condition, then the equipment would be removed and redeployed within the system or incorporated into the reconstruction.

HCHI has very few concrete poles (i.e. its ACA reports 440 concrete poles as compared to 26,912 wood poles), and as such, will focus its response on wood poles. HCHI has increased the useful life of wood poles from 45 years to 50 years. An analysis of wood poles replaced by age indicated HCHI is typically replacing poles at an average age of 49 years (refer to Exhibit 4 / Tab 3 / Schedule 2 / Table 16). Similarly, HCHI has adjusted the useful life of conductor to 50 years to match the useful life of wood poles. In this instance, strict adherence to the TUL in the Kinectrics Report actually leads to a mismatch between poles (i.e. 45 years) and conductor (i.e. 60 years). HCHI observes that there could be a mismatch in the useful life of a concrete pole and conductor, but that mismatch would occur on a much larger scale with wood poles (45) and conductor (60) if HCHI did not adjust the useful life of wood poles and conductor to match; that is, and instead applied the TUL from the Kinectrics Report.

b. Please review asset lives and remaining lives and set group rates where HCHI feels it is appropriate.

<u>HCHI Response</u>

HCHI believes that it has set appropriate depreciation periods based on its assets' lives and remaining useful lives and does not require any changes.

c. If HCHI feels that assets should not be grouped, please explain whether or how this is optimal from the perspective of financial performance.

<u>HCHI Response</u>

Refer to response in a.

7.2 VECC 26.

Reference: E4/T3/S3

Please provide an estimate of the 2014 revenue requirement impact of HCHI's departure from the Kinectric's recommended TUL for Poles, Overhead Conductors and Smart Meters.

<u>HCHI Response</u>

The rationale for HCHI's departure from the Kinectrics Report suggested TUL for poles and overhead conductor, which is within the range of the suggested minimum and maximum useful lives, is provided in response to Staff IR # 25 a. With respect to smart meters, the Kinectrics Report does not provide a TUL, but rather a useful life range of between 5 and 15 years. HCHI adopted a useful life of 15 years. Accordingly, HCHI has not processed the detailed calculations required to provide an estimate of the 2014 revenue requirement impact of these departures which are supported based on its specific experience.

7.3 Are the proposed levels of taxes appropriate?

7.3 EP 17.

Reference: Exhibit 4, Tab 4, Schedule 1

a. **Please confirm that computer software has been placed in CCA class 50 in both 2013 and 2014 in Table 23.**

HCHI Response

HCHI confirms computer software has been placed in CCA Class 50 for both the 2013 Bridge Year and the 2014 Test Year. CCA Class 50 also includes computer hardware for the both of these years.

b. **Please provide a version of Table 23 for 2013 and 2014 that places computer software in CCA class 12, with rate of 100% rather than in class 50 with a rate of 55%.**

HCHI Response

HCHI has provided an updated Table 23 providing CCA schedules for the 2013 Bridge Year and the 2014 Test Year with computer software placed in CCA Class 12 instead of CCA Class 50.

Table 23

UCC, CCA, and CEC Continuity Schedules – Change in Computer Software

2013 ACTUAL

Class	Class Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Rule	1/2 Year Rule {1/2 Addn's Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 22,109,558	$ -	$ -	$ 22,109,558	$ -	$ 22,109,558	4%	$ 884,382	$ 21,225,176
8	General Office/Stores Equip	$ 926,749	$ 51,345	$ (1,023)	$ 977,071	$ 25,161	$ 951,910	20%	$ 190,382	$ 786,689
10	Computer Hardware / Vehicles	$ 667,015	$ 260,503	$ (50,273)	$ 877,245	$ 105,115	$ 772,130	30%	$ 231,639	$ 645,606
12	Computer Software	$ -	$ 96,016	$ -	$ 96,016	$ 48,008	$ 48,008	100%	$ 48,008	$ 48,008
17	Parking Lots, sidewalks	$ 48,704	$ -	$ -	$ 48,704	$ -	$ 48,704	8%	$ 3,896	$ 44,808
45	Computers & Systems Software (post Mar 22, 2004)	$ 3,326	$ -	$ -	$ 3,326	$ -	$ 3,326	45%	$ 1,497	$ 1,829
46	Data Network Infrastructure Equipment (post Mar 22,2004)	$ 97	$ -	$ -	$ 97	$ -	$ 97	30%	$ 29	$ 68
47	Distribution System (post February 2005)	$ 21,143,554	$ 3,845,829	$ (1,697,038)	$ 23,292,345	$ 1,074,396	$ 22,217,950	8%	$ 1,777,436	$ 21,514,909
50	Computers & Systems Software (post Mar 18, 2007)	$ 114,725	$ 48,671	$ -	$ 163,396	$ 24,336	$ 139,061	55%	$ 76,483	$ 86,913
1 b	Buildings (post March 18, 2007)	$ 63,446	$ 1,450	$ -	$ 64,896	$ 725	$ 64,171	6%	$ 3,850	$ 61,046
	UCC and CCA - TOTAL	$ 45,077,174	$ 4,303,814	$ (1,748,334)	$ 47,632,654	$ 1,277,740	$ 46,354,914		$ 3,217,603	$ 44,415,051

		CEC Bridge Year Opening Balance	Additions at 100%		CEC Before Reduction for Additions	Reduction of 25% for Additions	CEC Balance prior Current Year Deduction	Rate %	Bridge Year CEC Deduction	CEC Bridge Year Closing Balance
CEC	Cumulative Eligible Capital	$ 221,932	$ 29,835	$ -	$ 251,767	$ 7,459	$ 244,308	7%	$ 17,102	$ 227,207

2014 TEST YEAR INTERROGATORY RESPONSES

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Rule	1/2 Year Rule {1/2 Addn's Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 21,225,176	$ -	$ -	$ 21,225,176	$ -	$ 21,225,176	4%	$ 849,007	$ 20,376,169
8	General Office/Stores Equip	$ 786,689	$ 72,250	$ -	$ 858,939	$ 36,125	$ 822,814	20%	$ 164,563	$ 694,376
10	Computer Hardware / Vehicles	$ 645,606	$ 218,400	$ -	$ 864,006	$ 109,200	$ 754,806	30%	$ 226,442	$ 637,564
12	Computer Software	$ 48,008	$ 280,645	$ -	$ 328,653	$ 140,323	$ 188,331	100%	$ 188,331	$ 140,323
17	Parking Lots, sidewalks	$ 44,808	$ -	$ -	$ 44,808	$ -	$ 44,808	8%	$ 3,585	$ 41,223
45	Computers & Systems Software (post Mar 22, 2004)	$ 1,829	$ -	$ -	$ 1,829	$ -	$ 1,829	45%	$ 823	$ 1,006
46	Data Network Infrastructure Equipment (post Mar 22,2004)	$ 68	$ -	$ -	$ 68	$ -	$ 68	30%	$ 20	$ 48
47	Distribution System (post February 2005)	$ 21,514,909	$ 5,997,773	$ -	$ 27,512,682	$ 2,998,887	$ 24,513,796	8%	$ 1,961,104	$ 25,551,578
50	Computers & Systems Software (post Mar 18, 2007)	$ 86,913	$ 109,344	$ -	$ 196,257	$ 54,672	$ 141,585	55%	$ 77,872	$ 118,385
1 b	Buildings (post March 18, 2007)	$ 61,046	$ -	$ -	$ 61,046	$ -	$ 61,046	6%	$ 3,663	$ 57,383
	UCC and CCA - TOTAL	$ 44,415,052	$ 6,678,412	$ -	$ 51,093,464	$ 3,339,206	$ 47,754,258		$ 3,475,408	$ 47,618,056

		CEC Bridge Year Opening Balance	Additions at 100%		CEC Before Reduction for Additions	Reduction of 25% for Additions	CEC Balance prior Current Year Deduction	Rate %	Bridge Year CEC Deduction	CEC Bridge Year Closing Balance
CEC	Cumulative Eligible Capital	$ 227,207	$ 441,675	$ -	$ 668,882	$ 110,419	$ 558,463	7%	$ 39,092	$ 519,371

c. Based on the response to part (b) above, what is the impact on the 2014 CCA?

<u>HCHI Response</u>

With respect to only the change in computer software (i.e. from CCA Class 50 to Class 12) would result in an increase of $29,628 in the 2014 CCA.

7.3 EP 18.

Reference: Exhibit 4, Tab 4, Schedule 1, PILS Workform

Please show the calculation of the apprenticeship tax credits of $26,000 shown in the PILS workform, including the number of positions eligible for and the amount associated with each position for the Ontario apprenticeship tax credit, the Ontario co-op education tax credit and the federal job creation tax credit.

<u>HCHI Response</u>

HCHI has provided for two positions eligible for the Ontario apprenticeship tax credit ("ATTC") and two positions eligible for the Ontario co-op education tax credit ("CETC"). One apprentice was hired November 19, 2012 with the other to be hired by March 1, 2014.

The ATTC was calculated at the $10,000 maximum (2 positions X $10,000 = $20,000) and the CETC was calculated at the $3,000 maximum (2 positions X $3,000 = $6,000) for a total credit of $26,000 ($20,000 + $6,000).

7.4 Is the proposed allocation of shared services and corporate costs appropriate?

7.4 EP 19.

Reference: Exhibit 1, Tab 5, Schedule 10

a. Does the test year revenue requirement for 2014 include any costs associated with the Board of Directors for any of the affiliates shown in the corporate structure chart? If yes, please provide the amount included in the revenue requirement associated with each affiliate and explain how the amount has been calculated and allocated.

HCHI Response

The 2014 Test Year does not include any costs associated with the Board of Directors for HCHI's affiliates.

b. Do the historical OM&A costs shown in the application for 2010 through 2013 (forecast) include any costs associated with the Board of Directors for any of the affiliates shown in the corporate structure chart? If yes, please provide the amount included in the OM&A associated with each affiliate for each of the years.

HCHI Response

The historical OM&A costs for 2010 through 2013 inclusive do not include any Board of Director costs for any of HCHI's affiliates.

7.4 EP 20.

Reference: Exhibit 4, Tab 2, Schedule 5 &
Exhibit 3, Tab 3, Schedule 1

a. Please show where the HCHI charges to its affiliates shown in Table 8 in Exhibit 4, Tab 2, Schedule 4 are included in Table 37 in Exhibit 3, Tab 3, Schedule 1.

HCHI Response

The referenced Table 8 is a summary of charges to affiliates for services provided by HCHI. The referenced Table 37 is a summary of Other Operating Revenue. None of the charges to HCHI's affiliates, as found on Table 8, are included in Table 37; that is, with the exception of the Water & Wastewater Billing & Collecting Fee. HCHI continues to apply the same methodology with respect to charges to its affiliates since its 2010 COS. With respect to those charges to affiliates included in Table 8 and not in Table 37, HCHI provides these services on a cost-based price plus mark-ups to cover overheads. Affiliate charges for such items as tree trimming and removals, pole relocations, and the supply and installation of transformers are handled through MARs as recoverable work. Affiliate charges for the repair, installation, billing and collecting of sentinel lights are based upon timesheets using the same burdened rates as charged for non-affiliate services, and directly charged to the affiliate, with the associated overhead mark-ups recorded as offsets against the various payroll, building maintenance and truck burden OM&A expense accounts included in the 2014 Test Year.

b. The costs allocated to the affiliates related to trucks are based on a unit rate. Does this unit rate include depreciation expenses associated with the trucks? If not, why not?

HCHI Response

The truck unit rate allocated to the affiliates does include a component of depreciation. The truck unit rate is derived as an average of all of the annual truck maintenance costs, including depreciation. However, and as reported in

Exhibit 2 / Tab 5 / Schedule 5 / Table 26, the "Vehicle Rates per Hour" have remained largely unchanged since the 2010 Board-approved amounts. Accordingly, the total charge on an annual basis for the depreciation component is not identifiable due to the historic setting of the unit rate.

c. Please show the costs associated with the revenues received from affiliates shown in Table 8 for the 2014 test year.

HCHI Response

As discussed in response to a., the only costs included in the 2014 Test Year with respect to Table 8 revenues received are on account of the Water & Wastewater Billing & Collecting fee. Refer to response to EP IR # 25 d. for a summary of those costs.

d. Are the 2014 test year costs requested in part (c) above included in the 2014 OM&A expenses? If not, where are these costs shown in the application?

HCHI Response

Refer to the response in a. and c.

e. Where in Table 37 in Exhibit 3, Tab 3, Schedule 1 is the $6,000 management fee charged by HCHI to HCUI noted on page 4 of Exhibit 4, Tab 2, Schedule 5 included?

HCHI Response

The $6,000 management fee discussed in Exhibit 4 / Tab 2 / Schedule 5 / Page 4 is not related to HCHI. It is a management fee charged from Haldimand County Utilities Inc. ("HCUI") to Haldimand County Energy Inc. ("HCEI"), as stated, and will not appear in any of HCHI's costs or revenues.

7.4 EP 21.

Reference: Exhibit 4, Tab 2, Schedule 5

At lines 14-15 on page 1 it is stated that there are no Board of Director related costs for HCUI included in HCHI's costs. At lines 6-9 on page 4 it states that there is a $54,000 management fee charged to HCHI by HCUI for services provided by the parent company HCUI's Board of Directors for governance and oversight services on behalf of HCHI.

a. Please reconcile these two statements.

HCHI Response

There are no direct costs associated with HCUI or HCEI's Board of Directors related to meeting expenses, meeting per diems, annual remuneration, or conference and travel costs included in HCHI's costs. The indirect management fee costs paid by HCHI to HCUI is for governance and oversight services by its parent company's Board, and in response to this interrogatory, the amount of $54,000 has been removed from HCHI's OM&A costs. All updated tables and models that accompany these responses have been updated accordingly.

b. Why are these governance and oversight services not provided to HCHI by its own Board of Directors?

HCHI Response

HCUI is the parent company, answering directly to the Shareholder, which provides governance and oversight services to each of its affiliates including HCHI.

c. Please provide the 2010 through 2014 costs associated with HCHI/s Board of Directors.

HCHI Response

HCHI has provided its Board of Director costs in Exhibit 4 / Tab 2 / Schedule 2 / Table 6, which has now been updated in response to VECC IR # 9.

7.4 VECC 27.

Reference: E4/T2/S5

Re: Shared Billing.

a. **Please explain why there has been only a 2.5% increase in the charge for billing services (365k to 374k) and no increase since 2012 whereas in Table 6 HCHI shows an increase in Customer Billing of approximately 15%.**

   HCHI Response

   The 15% increase in Customer Billing is not all applicable to the cost of offering billing services. As one example, in 2012 HCHI's Customer Billing costs reflect the addition of the Sync Operator, which is a new position added on account of the implementation of smart meters. The Sync Operator costs are not included in the costs required to deliver shared billing services.

b. **Please provide all the USoA accounts related to the shared billing costs for HCHI for each year 2010 through 2014 and show the associated allocation of those costs to the Affiliate**.

   HCHI Response

   Refer to response to EP IR # 25 d.

7.5 Are the proposed capital structure, rate of return on equity and short and long term debt costs appropriate?

7.5 Staff 26. Cost of Capital

Reference: ***Board Letter, November 25, 2013: Cost of Capital Parameter Updates for 2014 Cost of Service Applications***

On November 25, 2013, the Board updated the cost of capital parameters for 2014 cost of service applications. Please update the application accordingly to incorporate these new parameters.

<u>HCHI Response</u>

HCHI has updated its application to reflect the Board's updated cost of capital parameters for 2014 Cost of Service Applications issued November 25, 2013.

7.5 EP 22.

Reference: Exhibit 5, Tab 1, Schedule 2

Please update the 2014 portion of Table 1 to reflect the update cost of capital parameters applicable to 2014 cost of service applications, as issued by the Board on November 25, 2013.

HCHI Response

HCHI has updated the 2014 portion of Table 1 in Exhibit 5 in accordance with the Board's updated cost of capital parameters applicable to 2014 cost of service rate applications and with HCHI's response to EP IR # 23 d. as follows:

Table 1
Capitalization and Cost of Capital

Deemed Capital Structure for 2014

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	30,127,476	56.00%	2.89%	870,684
Unfunded Short Term Debt	2,151,963	4.00%	2.11%	45,406
Total Debt	32,279,438	60.00%		916,090
Common Share Equity	21,519,626	40.00%	9.36%	2,014,237
Total equity	21,519,626	40.00%		2,014,237
Total Rate Base	53,799,064	100.00%	5.45%	2,930,327

7.5 EP 23.

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

a. What is the status of the Infrastructure Ontario financing that was expected to be in place by late 2013? If financing is now in place, please provide the details of this financing, including the amount and the applicable rate.

HCHI Response

The Infrastructure Ontario ("IO") financing expected to be in place by late 2013 did not occur. HCHI is currently in the process of securing financing in the amount of $7.5 million on account of 2013 and 2014 capital expenditures, with its bank, the CIBC, through Bankers Acceptances with an effective interest rate of 2.07% (includes CIBC's stamping fee of 0.75%) as of February 18, 2014. The first draws against this financing are expected to occur in late Q1/2014.

b. When does HCHI expect to convert this loan into a long-term debenture?

HCHI Response

Refer to response in a.

c. What is the current Infrastructure Ontario interest rate on a 25 year loan?

HCHI Response

IO's indicative lending rate as of February 26, 2014 on a 25-year serial debenture is 4.06%.

d. Please update the 2014 portion of Table 2 in Exhibit 5, Tab 1, Schedule 3 to reflect the responses in parts (a), (b) and (c) above.

HCHI Response

The 2014 portion of Table 2 in Exhibit 5 / Tab 1 / Schedule 3 is updated as follows:

Table 2
Long-Term Debt Details and Weighted Cost – "2014"

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)
1	Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 192,998	2.92%	$ 5,635.54
2	Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 3,173,018	3.90%	$ 123,747.70
3	Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	15	$ 2,933,333	4.39%	$ 128,773.32
4	Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	25	$ 5,664,501	3.76%	$ 212,985.24
5	Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	10	$ 595,492	2.88%	$ 17,150.17
6	Financing	CIBC	Third-Party	Variable Rate	1-Mar-14	Monthly	$ 2,500,000	2.07%	$ 43,125.00
7	Financing	CIBC	Third-Party	Variable Rate	1-Jun-14	Monthly	$ 2,500,000	2.07%	$ 30,187.50
8	Financing	CIBC	Third-Party	Variable Rate	1-Sep-14	Monthly	$ 2,500,000	2.07%	$ 17,250.00
Total							$ 20,059,342	2.89%	$ 578,854.47

7.6 Is the proposed forecast of other revenues including those from specific service charges appropriate?

7.6 EP 24.

Reference: Exhibit 3, Tab 3, Schedule 1

Please update Table 37 to reflect actual data for 2013, excluding the PPE adjustment. If actual data is not yet available for all of 2013, please provide the most recent year-to-date figures available for 2013 in the same level of detail as shown in Table 37 and also provide the figures for the corresponding period in 2012.

HCHI Response

HCHI has updated Table 37 to reflect 2013 actual data (internally prepared and unaudited), excluding the PPE adjustment, as follows.

Table 37
Summary of Other Operating Revenue
(Excluding PPE Adjustment)

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual²	2013 Actual²	Test Year
						2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4235	Specific Service Charges	$ 136,247	$ 109,529	$ 122,565	$ 114,107	$ 120,987
4225	Late Payment Charges	349,416	289,018	319,383	358,659	310,717
4082	Retail Services Revenue	31,747	29,584	26,639	23,936	26,720
4084	STR Revenues	1,045	841	498	382	1,010
4086	SSS Administration Revenue	64,723	65,103	58,184	58,847	68,148
4210	Rent from Electric Property	80,923	86,987	76,396	83,239	76,226
4305	Regulatory Debits					
4324	Special Purpose Charge Recovery	94,692	46,517			
4325	Revenues from Merchandise	18,976	22,402	19,646	26,248	16,873
4355	Gain on Disposition of Utility & Other Property	12,203	24,427	114,495	13,492	13,940
4360	Loss on Disposition of Utility & Other Property	(6,685)	(3,078)	(1,959)		
4375	Revenues from Non Rate-Regulated Utility Operations	365,737	364,650	374,857	375,366	374,205
4380	Expenses of Non Rate-Regulated Utility Operations	(1)				
4390	Miscellaneous Non-Operating Income	68,196	144,190	154,277	118,846	90,585
4405	Interest and Dividend Income	27,884	28,211	42,514	65,826	38,650
Specific Service Charges		$ 136,247	$ 109,529	$ 122,565	$ 114,107	$ 120,987
Late Payment Charges		$ 349,416	$ 289,018	$ 319,383	$ 358,659	$ 310,717
Other Operating Revenues		$ 178,438	$ 182,515	$ 161,717	$ 166,404	$ 172,104
Other Income and Deductions		$ 581,002	$ 627,319	$ 703,830	$ 599,778	$ 534,253
Total		$ 1,245,103	$ 1,208,381	$ 1,307,495	$ 1,238,948	$ 1,138,061

7.6 EP 25.

Reference: Exhibit 3, Tab 3, Schedule 1

a. Please confirm that Account 4375 includes revenues associated with water and sewer billing fees.

HCHI Response

HCHI confirms that Account 4375 includes revenues associated with Water and Wastewater billing and collecting fees.

b. Are there any other revenue sources in Account 4375 other than water and sewer billing fees?

HCHI Response

There are no other revenues recorded in Account 4375.

c. There are no costs shown in Account 4380 related to the revenues in Account 4375. Please explain how the costs associated with the revenues in Account 4375 are accounted for. For example, are these costs included in the OM&A figures for the historical, bridge and test years?

HCHI Response

The only revenues reported in Account 4375 are related to Water and Wastewater billing and collecting fees. The costs associated with these revenues are recorded in various OM&A accounts for historical years, the Bridge Year, and the Test Year.

d. Please provide the associated costs incurred in providing the services for which revenue is shown in Account 4375 for each of 2010 through 2014.

HCHI Response

The portion of the total billing and collecting operating and administrative costs attributable to the Water and Wastewater billing and collecting fees for each of 2010 through to 2014 are provided in the following table.

Water & Wastewater Billing & Collecting Costs
2010 through to 2014

	ACTUAL EXPENSES as at December 31, 2012						BUDGET			
	2010		2011		2012		2013		2014	
	12 Month Actual		12 Month Actual		12 Month Actual		12 Month Bridge Year		12 Month Test Year	
DIRECT EXPENSES										
Labour	$ 691,823		$ 695,158		$ 745,382		$ 792,292		$ 819,322	
Olameter - Disconnects & Collections	$ 93,237		$ 62,381		$ 77,151		$ 78,000		$ 78,000	
Postage	$ 192,916		$ 180,734		$ 212,856		$ 221,896		$ 221,440	
Office and Printing	$ 41,441		$ 39,298		$ 41,829		$ 39,478		$ 32,864	
SUB-TOTAL DIRECT EXPENSES	$ 1,019,417		$ 977,571		$ 1,077,218		$ 1,131,666		$ 1,151,626	
INDIRECT/OVERHEAD EXPENSES										
Building	$ 128,421		$ 127,875		$ 126,641		$ 142,295		$ 142,304	
Amortization	$ 306,738		$ 319,296		$ 314,931		$ 315,113		$ 243,590	
IT Support - (CIS / Financial / Network)	$ 161,983		$ 174,082		$ 204,909		$ 202,420		$ 206,522	
SUB-TOTAL INDIRECT/OVERHEAD EXPENSES	$ 597,142		$ 621,253		$ 646,481		$ 659,828		$ 592,416	
TOTAL EXPENSES (before Meter Reading)	$ 1,616,559		$ 1,598,824		$ 1,723,699		$ 1,791,494		$ 1,744,042	
Allocation of Total Costs Based on Number of Water & Wastewater Customers Billed	$ 475,430	29.41%	$ 470,534	29.43%	$ 509,525	29.56%	$ 529,566	29.56%	$ 515,539	29.56%
per Water / Waste Water Billed Customer per month	$ 4.52		$ 4.45		$ 4.76		$ 4.95		$ 4.82	
Meter Reading Cost - per meter	$ 0.38		$ 0.37		$ 0.37		$ 0.37		$ 0.37	
TOTAL COST per WATER / WASTE WATER BILLED CUSTOMER PER MONTH	$ 4.90		$ 4.82		$ 5.13		$ 5.32		$ 5.19	
Automated Meter Reading (AMR) - Credits Commencing June 2012 *Note:* June 2013 - credits issued on account of 2076 meters					$ (0.37)		$ (0.37)		$ (0.37)	
ACTUAL RATE CHARGED	$4.10 effective April 1, 2008				$4.22 effective April 1, 2012					

The per bill and total charge on an annual basis specific to the current Water and Wastewater billing and collecting fee (the "Fee") being charged is not identifiable due to the history associated with the setting of the fee and the mitigation of fee increases. The Fee paid by Haldimand County to Haldimand County Energy Inc. was increased by 91.6% for a compounded average of 11.5% per year from $2.14 per bill in 2002 to $4.10 per bill in 2008, and then increased by an inflationary 3.0% to $4.22 per bill in 2012. The customers of HCHI benefit from this billing arrangement because the revenue exceeds the marginal cost as evidenced by the fixed nature of some of the costs recovered by the arrangement. It is also important that the cost to the municipality be market based as they compare their alternatives. The Fee was not increased in 2009, 2010, 2011, 2013 and 2014 in order to avoid becoming uncompetitive and possibly losing the arrangement.

7.6 EP 26.

Reference: Exhibit 3, Tab 3, Schedule 2

a. Please explain why HCEI only pays HCHI 85% of what it charges to Haldimand County for the water and sewer billing services.

HCHI Response

Since the inception of the billing and collecting contract between HCEI and HCHI during 2003, HCEI has retained 15% of the associated fees as profit on its services.

b. What does HCEI add to the billing process that HCHI does not do?

HCHI Response

Governance and oversight services, and administration of the contract.

7.6 VECC 28.

Reference: E3/T3/S1, pages 61-2

a. Please provide versions of Tables 37 and 38 with the actual 2013 values.

<u>HCHI Response</u>

HCHI has updated Tables 37 as part of its response to EP IR # 24 and now provides updated Table 38.

Table 38
Detailed Account Breakdown

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Account 4082 - Retail Service Revenue					
Retail Service Agreement Revenue	31,747	29,584	26,639	23,936	26,720
Total	31,747	29,584	26,639	23,936	26,720
Account 4084 - STR Revenue					
Retail Service Transaction Requests (STR) Revenue	1,045	841	498	382	1,010
Total	1,045	841	498	382	1,010
Account 4086 - SSS Administration Revenue					
SSS Administration Revenue	64,723	65,103	58,184	58,847	68,148
Total	64,723	65,103	58,184	58,847	68,148
Account 4210 - Rent from Electric Property					
Pole Rental Revenue	80,923	86,987	76,396	83,239	76,226
Total	80,923	86,987	76,396	83,239	76,226
TOTAL OTHER OPERATING REVENUE	**178,438**	**182,515**	**161,717**	**166,404**	**172,104**
Account 4305 - Regulatory Debits					
PPE Useful Lives Adjustment (effective January 1, 2013)				(1,459,184)	
Total	-	-	-	(1,459,184)	-
Account 4324 - Special Purpose Charge Recovery					
Special Purpose Charge Recovery	94,692	46,517			
Total	94,692	46,517	-	-	-
Account 4325 - Revenues from Merchandis, Jobbing, Etc.					
Profit from Sale of Services	18,976	22,402	19,646	26,248	16,873
Total	18,976	22,402	19,646	26,248	16,873
Account 4355 - Gain on Disposition of Utility & Other Property					
Gain on Disposal of Other Property	12,203	24,427	114,495	13,492	13,940
Total	12,203	24,427	114,495	13,492	13,940
Account 4360 - Loss on Disposition of Utility & Other Property					
Loss on Disposal of Other Property	(6,685)	(3,078)	(1,959)		
Total	(6,685)	(3,078)	(1,959)	-	-
Account 4375 - Revenues from Non-Rate Regulated Operations					
Revenue from Water & Sewer Admin Fee (85%)	365,737	364,650	374,857	375,366	374,205
Total	365,737	364,650	374,857	375,366	374,205
Account 4380 - Expenses from Non-Rate Regulated Utility Opera					
Write-off of Balance in '1590' RAR account - activity after disposition approval unrecoverable	(1)				
Total	(1)	-	-	-	-
Account 4390 - Miscellaneous Non-Operating Income					
Revenues from Long-term Load Transfers	59,422	59,538	92,807	37,667	52,400
Revenues from Short-term Load Transfers		74,704	52,644	15,981	
Revenue from Lawyers Letters	1,860	1,965	2,370	2,250	2,487
Proceeds - from sale of Enerconnect Limited Partnership	4,775	4,736			
Revenue from Theft of Power		2,482	747	10,334	
"Caledonia Class Action" settlement compensation award - Douglas Creek Estates (Native occupation)			5,000		
Revenue from Generator Admin Fees (RESOP, FIT, HOEP)				27,990	35,663
Revenue from Cost Contribution Agreement - Renewable Transmission Project (Distribution Line Infrastructure Improvements)				24,088	
Other Miscellaneous Income	2,139	765	709	536	35
Total	68,196	144,190	154,277	118,846	90,585
Account 4405 - Interest and Dividend Income					
Interest on Bank Account	27,332	27,529	41,984	65,405	38,188
Mortgage Interest	552	545	530	421	462
Miscellaneous Interest		137			
Total	27,884	28,211	42,514	65,826	38,650
TOTAL OTHER INCOME AND DEDUCTIONS	**581,002**	**627,319**	**703,830**	**(859,406)**	**534,253**

b. **Please explain why there is no forecast revenue from short-term load transfers for either 2013 or 2014.**

HCHI Response

HCHI does not expect to incur short-term load transfers in any given year and therefore does not forecast any revenue that is uncertain to happen. HONI made improvements at the transformer stations to minimize future short-term load transfers.

c. **What is the basis for the projected 2013 and 2014 values for Account #4325?**

HCHI Response

Account 4325 is forecast based on trending historical actuals.

d. **Please explain the decline in pole rental revenue in 2012.**

HCHI Response

HCHI reports its pole revenue net of the expense of HCHI's assets on other utility poles and the revenue collected from other utilities for their assets on HCHI's poles. In any year, the change in revenue is the net cumulative impact of all of the changes to both the revenue and expenses. In 2011, HCHI installed conductor on 153 of HONI poles in order to supply HCHI customers to eliminate Long-term Load Transfers. The additional charge for 2011 and for 2012 were both recorded in the 2012 actual pole rental revenue.

7.7 Has the proposed revenue requirement been accurately determined from the operating, depreciation and tax (PILs) expenses and return on capital, less other revenues?

7.7 Staff 27. Updates

Reference: Various specified Exhibits.

Upon completing all interrogatories from Board staff and intervenors, please provide the following updates and in live excel format as required:

- **RRWF;**
- **PILS**
- **Appendix 2-AA; Capital Projects Table**
- **Appendix 2-AB; Capital Expenditure**
- **Appendix 2-CT; 2013 Depreciation & Amortization Expense (CGAAP)**
- **Appendix 2-CU; 2014 Depreciation & Amortization Expense (CGAAP)**
- **Appendix 2EE; Account 1576 Accounting Change Under CGAAP**
- **Appendix 2-P; Cost Allocation**
- **Appendix 2-W; Rate Impacts**
- **Appendix 2-YB; Accounting Change Under CGAAP Summary Impacts**
- **Appendix 2-Z; Tariff & Schedules**
- **Cost Allocation Model; and**
- **Tariff of Rates and Charges**

HCHI Response

Updates required in response to each of the interrogatories have been completed in each of the applicable models and appendices which will have been filed in Excel format to the Board.

7.7 EP 27.

Reference: Exhibit 6, Tab 1, Appendix A

a. **Please update the RRWF to reflect any changes or corrections resulting from the interrogatory responses, as well as the updated cost of capital parameters applicable to 2014 cost of service applications as issued by the Board on November 25, 2013.**

HCHI Response

Updated as noted in response to Staff IR # 27.

b. **Please provide a tracking sheet showing the changes and/or corrections made to the revenue deficiency/sufficiency calculation as noted in part (a) above. For each change, please provide a reference to the associated interrogatory response that results in the change.**

HCHI Response

Tracking sheet provided as part of RRWF as noted in response to a.

8 Load Forecast, Cost Allocation and Rate Design

8.1 Is the proposed load forecast, including billing determinants, an appropriate reflection of the energy and demand requirements of the applicant?

8.1 Staff 28. Embedded Rate Class

Reference: Exhibit 3 Tab 2 Schedule 2

On page 6 HCHI states that HONI did not develop a forecast for its embedded class but rather relied upon HCHI's supplied forecast for 2013 and 2014. Did HCHI undertake any tests for reasonableness of the forecast?

<u>HCHI Response</u>

HCHI did look at actual load for its Embedded Distributor – HONI for the years 2011 and 2012 for reasonableness of the load forecast provided by HONI for the Bridge Year 2013 and the Test Year 2014 as illustrated in Table 36 of Exhibit 3 / Tab 2 / Schedule 2. HONI has used this data for its own purposes in forecasting load and would have numerous years of historical data on these metering points, whereas, when HCHI prepared this application it only had complete 12 month data for the years 2010 through to and including 2012 with a partial year in 2009, when HONI became embedded to HCHI.

8.1 Staff 29. CDM Programme Net Savings

Reference: Exhibit 3 Tab 2 Schedule 2

On pages 23 & 24 HCHI states that the 2013 and 2014 net energy savings have been allocated based on "Program-to-Date Verified Progress to Target" 2011 to 2014 net cumulative energy savings (kWh) by program as detailed in the 2012 OPA 21 Annual CDM Report 2012 – Draft Verified Results.

a. Has this report been finalized?

HCHI Response

Yes, final results were received from the OPA on August 30, 2013 in the report "Ontario Power Authority Final Verified 2012 Conservation and Demand Management Results" submitted in Exhibit 9 / Tab 6 / Schedule 2 / Appendix F.

b. If it has been finalized, please update the forecast.

HCHI Response

The load forecast included the OPA-CDM final 2012 verified results as discussed in Exhibit 3 / Tab 2 Schedule 2 / Pages 10 to 12 and Pages 22 to 23. It was only the allocation to the three customer rate classes discussed on Pages 23 to 24 of Exhibit 3 that had been allocated based on the draft verified results. These allocation percentages have now been updated to include the 2012 final verified CDM results as requested. Refer to Excel file "Haldimand_2014_Load Forecasting Model_20140304".

Allocation of OPA-CDM Final 2012 Verified Results to Customer Classes

	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Total
2013 Bridge Year	31.92%	30.19%	37.89%	100.00%
2014 Test Year	31.92%	30.19%	37.89%	100.00%

HCHI also states that some initiatives apply to more than one customer rate class, such as the Retrofit initiative under the Business programs. In such cases, HCHI estimated the customer rate class allocation by utilizing participant-specific information and provided the example that its Retrofit initiative was split 50 /50 between the two General Service customer rate classes.

Please provide the total percentage split that resulted from utilizing participant-specific information between the general service classes for all OPA initiatives in the 2013 & 2014 OPA programmes.

<u>HCHI Response</u>

The participant-specific information between the General Service classes for all OPA CDM programs is as follows:

Participant-Specific Information – General Service Customer Classes

	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Total
Business Program:			
Efficiency: Equipment Replacement	50%	50%	100%
Direct Install Lighting	100%		100%
New Construction and Major Renovation Incentive		100%	100%
Industrial Program:			
Demand Response 3		100%	100%
Pre-2011 Programs completed in 2011/2012			
Electricity Retrofit Incentive Program	60%	40%	100%
High Performance New Construction		100%	100%

Calculations for the updated allocation percentages between the three customer rate classes based on the OPA-CDM final 2012 verified results are included in the table below.

Customer Rate Class Percentage Allocation of Estimated 2013 / 2014 CDM Net Savings
Updated for OPA-CDM Final 2012 Verified Results

OPA 2011 - 2014 Cumulative Results			2013 / 2014 Estimated Results per Load Forecast Model							
Initiative	Net Savings (kWh)	Initiative kWh Net Savings to Total	Net Savings (kWh)	Residential Participant-Specific Allocation	General Service Less than 50 kW Participant-Specific Allocation			General Service 50 to 4,999 kW Participant-Specific Allocation		
				100%	100%	50%	60%	50%	40%	100%
Consumer Program			(see Note 2)	(see Note 3)	(see Note 3)	(see Note 3)	(see Note 3)	(see Note 3)	(see Note 3)	(see Note 3)
Appliance Replacement	647,542.00	7.02%	95,004.05	95,004.05						
Appliance Exchange	36,839.00	0.40%	5,413.34	5,413.34						
HVAC Incentives	942,639.00	10.22%	138,310.73	138,310.73						
Conservation Instant Coupon Booklet	347,672.00	3.77%	51,020.69	51,020.69						
Bi-annual Retailer Event	876,949.00	9.51%	128,702.06	128,702.06						
Residential Demand Response	55.00	0.00%	-	-						
Residential New Construction	1,245.00	0.01%	135.33	135.33						
	2,852,941.00	30.93%	418,586.20	418,586.20	-	-	-	-	-	-
Business Program										
Efficiency: Equipment Replacement	3,379,076.00	36.66%	496,132.24			248,066.12	-	248,066.12	-	
Direct Install Lighting	1,034,324.00	11.22%	151,844.07		151,844.07					
New Construction and Major Renovation Incentive	295,811.00	3.21%	43,442.02							43,442.02
	4,709,211.00	51.09%	691,418.33		151,844.07	248,066.12	-	248,066.12	-	43,442.02
Industrial Program										
Demand Response 3 (see Note 1)	4,351.00	0.05%	676.67	N/A						676.67
	4,351.00	0.05%	676.67		-	-	-	-	-	676.67
Home Assistance Program										
Home Assistance Program	91,679.00	0.99%	13,398.01	13,398.01						
	91,679.00	0.99%	13,398.01	13,398.01	-	-	-	-	-	-
Pre-2011 Programs completed in 2011 / 2012										
Electricity Retrofit Incentive Program	98,518.00	1.07%	14,480.67				8,688.40		5,792.27	
High Performance New Construction	1,463,130.00	15.87%	214,774.11							214,774.11
	1,561,648.00	16.94%	229,254.78		-	-	8,688.40	-	5,792.27	214,774.11
	9,219,830.00	100.00%	1,353,334.00	431,984.21	151,844.07	248,066.12	8,688.40	248,066.12	5,792.27	258,892.80
CDM Target (2011 to 2014)	13,300,000.00									-
	69.3%		100.00%	31.92%		30.19%			37.89%	

Notes:
1. OPA assumes "Demand Response" programs have a persistence of 1 year only
2. 2013 / 2014 Estimated Results per calculation in Load Forecast model - allocated by initiative based on actual initiative kWh net savings to total in "OPA 2011 - 2014 Cumulative Results".
3. Percentage allocation to customer classes based on allocation from OPA 2012 Final Verified Results in Indeco's LRAM calculator spreadsheet

8.1 Staff 30. Customer/Connection Forecast

Reference: Exhibit 3 Tab 2 Schedule 2 Table 21

HCHI states that the geometric mean of the annual growth rates by class was used to establish the customer/connection estimates for the bridge and forecast years. Table 21 on page 17 calculates each of the geometric means. Board staff would like HCHI's comments on the following observations:

a. HCHI is estimating an average growth rate for GS<50 kW of 0.3%, but over the 2010 – 2012 period there has been a net loss of customers.

HCHI Response

HCHI's forecast for the 2013 Bridge Year was the actual customer count as at July 31, 2013 with the geometric mean applied to this number to forecast the 2014 Test Year as stated in Exhibit 3 / Tab 2 / Schedule 2 / Page 18.

HCHI has reviewed this customer class actual count as at December 31, 2013 (2,342) and at January 31, 2014 (2,346) and has adjusted its load forecast model accordingly in response to Staff IR # 30 e.

b. HCHI is estimating an average decline for GS< 50 – 4,999 kW of -0.5%, but over the 2010 – 2012 period there has been a net increase of customers.

HCHI Response

HCHI's forecast for the 2013 Bridge Year was the actual customer count as at July 31, 2013 with the geometric mean applied to this number to forecast the 2014 Test Year as stated in Exhibit 3 / Tab 2 / Schedule 2 / Page 18.

HCHI has reviewed this customer class actual count as at December 31, 2013 (158) and at January 31, 2014 (159) and has adjusted its load forecast model accordingly in response to Staff IR # 30 e.

c. **How has HCHI determined the street lighting growth rate to be reasonable? Has it compared its forecast to municipal plans?**

HCHI Response

The geometric mean shows an increase of 1.1% in the Street Lighting connections for the period 2004 to 2012 where the actual connections have been decreasing over the period 2010 to 2012.

HCHI has reviewed this customer class actual count as at December 31, 2013 (2,977) and at January 31, 2014 (2,974) and feels the street lighting growth rate of nil to be reasonable.

HCHI has not compared its forecast to municipal plans. HCHI expects streetlight growth rate to be minimal.

d. **The decrease in USL connections has been greater in the 2010 – 2012 period than the HCHI's forecast of -2.1% for bridge and forecast years.**

HCHI Response

Over the years, HCHI has been installing a meter on these Unmetered Scattered Load ("USL") customers resulting in the decrease in number of connections currently at the end of 2013 of 69 to the forecast of 68 for the 2014 Test Year. Once the meter is installed, these customers move to the General Service Less Than 50 kW ("G/S < 50 kW") customer class.

HCHI feels that the number of USL accounts transitioning to the G/S < 50 kW customer class has tailed off and does not foresee a large number to become metered in the near future. The actual number of connections for the USL class at the end of January 31, 2014 is 69.

e. **If HCHI feels that any change to the forecast are needed as a result of the above, please make the change and provide reasons for the new customer/connection estimates.**

HCHI Response

HCHI has updated its 2013 customer / connection numbers to reflect actual data at the end of 2013. The geometric means have been recalculated inclusive of the change in customers from the end of 2012 to the end of 2013.

HCHI has taken Board Staff's observations into consideration and altered the formula for the General Service Less Than 50 kW customer rate class and not included the growth between the periods 2003 through to 2005. HCHI has updated the growth rate in customer / connections with the recalculation of the geometric means in Table 21, as follows.

Table 21
Growth Rate in Customers / Connections – Updated Geometric Mean

Year	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
2003						
2004	1.1%	0.6%	0.0%	2.4%	(14.9%)	(8.0%)
2005	0.7%	1.2%	0.0%	(0.5%)	(3.3%)	7.4%
2006	0.7%	(0.6%)	0.0%	(0.2%)	(1.7%)	1.1%
2007	0.6%	1.0%	(8.9%)	1.3%	(4.0%)	(4.5%)
2008	0.6%	0.3%	1.4%	3.0%	(2.7%)	0.0%
2009	0.4%	1.3%	(0.7%)	(0.2%)	1.4%	0.0%
2010	0.9%	(0.5%)	(0.7%)	5.0%	(9.5%)	(7.1%)
2011	0.4%	0.7%	1.4%	(1.7%)	(4.5%)	(2.6%)
2012	0.5%	(1.5%)	3.4%	0.6%	(5.6%)	(3.9%)
2013	0.5%	(0.1%)	5.3%	(0.2%)	(2.6%)	(5.5%)
Geometric Mean	0.6%	0.1%	0.1%	0.0%	(4.9%)	(2.4%)

8.1 EP 28.

Ref: Exhibit 3, Tab 1, Schedule 2

Please update Table 3 to reflect actual data for 2013.

HCHI Response

Table 3 has been updated to reflect 2013 actual data (internally prepared and unaudited).

Table 3
Summary of Operating Revenue
(Excluding Smart Meter Revenue & PPE Adjustment)

Description	2010 Board Approved	2010 Actual Year	2011 Actual Year	2012 Actual Year	2013 Actual Year	2014 Test Year Interrogatory Responses
Distribution Revenues:						
Residential	8,461,082	8,466,776	8,558,988	8,414,543	8,607,439	8,717,101
General Service Less Than 50 kW	2,057,572	1,916,178	1,961,828	1,950,500	1,978,697	1,666,279
General Service 50 to 4,999 kW	1,664,038	1,807,747	1,721,631	1,679,436	1,753,111	1,410,243
Street Lighting	195,717	158,262	295,390	299,950	316,988	315,301
Sentinel Lighting	73,999	45,765	88,497	123,186	111,775	114,609
Unmetered Scattered Load	21,999	19,410	18,684	18,114	16,593	17,438
Embedded Distributor - Hydro One Networks	172,340	545,693	165,467	156,476	153,062	369,483
Total Base Distribution Revenue Requirement	12,646,747	12,959,831	12,810,485	12,642,205	12,937,665	12,610,454
% of Total Revenue	92%	91%	91%	91%	91%	92%
Other Revenue:						
Late Payment Charges	319,125	349,416	289,018	319,383	358,659	310,717
Specific Service Charges	133,200	136,247	109,529	122,565	114,107	120,987
Other Operating Revenue	183,821	178,438	182,515	161,717	166,404	172,104
Other Income and Deductions	452,998	581,002	627,319	703,830	599,778	534,253
Total Other Revenue	1,089,144	1,245,103	1,208,381	1,307,495	1,238,948	1,138,061
% of Total Revenue	8%	9%	9%	9%	9%	8%
Total Service Revenue Requirement	13,735,891	14,204,934	14,018,866	13,949,700	14,176,613	13,748,515
Variance from 2010 Board Approved		3.41%	2.06%	1.56%	3.21%	0.09%
Variance from Prior Year			(1.31%)	(0.49%)	1.63%	(3.02%)

8.1 EP 29.

Reference: Exhibit 3, Tab 2, Schedule 2

Please update Tables 13 through 15 to reflect actual data for 2013.

HCHI Response

HCHI has updated Tables 13 through 15 to reflect 2013 actuals (internally prepared and unaudited).

Table 13
Billed Energy and Customer/Connection Counts
(Excluding Embedded Distributor Rate Class)

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change
2010 Board Approved	347.0			24,586		
2003 Actual	358.6			23,682		
2004 Actual	362.3	3.7	1.0%	23,816	134	0.6%
2005 Actual	373.4	11.1	3.1%	23,930	114	0.5%
2006 Actual	359.3	(14.1)	(3.8%)	24,033	103	0.4%
2007 Actual	360.3	1.0	0.3%	24,160	127	0.5%
2008 Actual	352.1	(8.3)	(2.3%)	24,343	183	0.8%
2009 Actual	338.5	(13.6)	(3.9%)	24,439	96	0.4%
2010 Actual	348.4	9.9	2.9%	24,658	219	0.9%
2011 Actual	350.0	1.5	0.4%	24,662	4	0.0%
2012 Actual	344.6	(5.4)	(1.5%)	24,701	39	0.2%
2013 Actual	348.0	3.4	1.0%	24,784	83	0.3%
2014 Test Year Interrogatory Responses	343.9	(4.1)	(1.2%)	24,867	83	0.3%

Table 14
Billed Energy and Customer/Connection Counts
(Including Embedded Distributor Rate Class)

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Embedded Distributor - HONI	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
Billed Energy (GWh)								
2010 Board Approved	172.0	61.8	110.0	83.2	2.3	0.4	0.5	430.2
2003 Actual	175.0	58.6	121.6	0.0	2.2	0.6	0.5	358.6
2004 Actual	172.2	56.3	130.4	0.0	2.2	0.6	0.5	362.3
2005 Actual	181.5	58.5	130.2	0.0	2.2	0.5	0.5	373.4
2006 Actual	171.5	56.7	127.8	0.0	2.2	0.5	0.5	359.3
2007 Actual	173.8	57.9	125.4	0.0	2.3	0.5	0.5	360.3
2008 Actual	171.8	57.8	119.2	0.0	2.3	0.5	0.5	352.1
2009 Actual	168.2	56.1	110.9	56.0	2.3	0.5	0.5	394.6
2010 Actual	172.2	56.2	117.0	73.9	2.2	0.4	0.5	422.3
2011 Actual	171.2	55.9	119.8	74.2	2.3	0.4	0.4	424.1
2012 Actual	168.3	54.8	118.3	71.8	2.4	0.4	0.4	416.4
2013 Actual	169.9	54.8	120.2	70.9	2.4	0.3	0.4	418.9
2014 Test Year Interrogatory Responses	168.2	53.6	119.0	72.6	2.4	0.3	0.4	416.5
Number of Customers/Connections								
2010 Board Approved	18,534	2,357	143	8	2,879	589	84	24,594
2003 Actual	17,585	2,282	157	0	2,713	857	88	23,682
2004 Actual	17,776	2,296	157	0	2,777	729	81	23,816
2005 Actual	17,893	2,324	157	0	2,764	705	87	23,930
2006 Actual	18,026	2,311	157	0	2,758	693	88	24,033
2007 Actual	18,139	2,335	143	0	2,794	665	84	24,160
2008 Actual	18,245	2,343	145	0	2,879	647	84	24,343
2009 Actual	18,309	2,374	144	8	2,872	656	84	24,447
2010 Actual	18,465	2,363	143	8	3,015	594	78	24,666
2011 Actual	18,531	2,380	145	8	2,963	567	76	24,670
2012 Actual	18,617	2,344	150	8	2,982	535	73	24,709
2013 Actual	18,717	2,342	158	8	2,977	521	69	24,792
2014 Test Year Interrogatory Responses	18,825	2,344	158	8	2,977	496	67	24,875

Table 15
Billed Energy and Customer/Connection Counts

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Embedded Distributor - HONI	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Energy Usage per Customer/Connection (kWh per customer/connection)							
2010 Board Approved	9,280	26,220	769,231	10,400,000	799	679	5,952
2003 Actual	9,953	25,686	774,580	0	819	686	6,125
2004 Actual	9,690	24,538	830,799	0	789	785	6,758
2005 Actual	10,142	25,185	829,339	0	788	766	5,907
2006 Actual	9,516	24,544	813,976	0	809	745	5,769
2007 Actual	9,581	24,789	876,724	0	822	737	5,944
2008 Actual	9,415	24,682	821,976	0	809	735	5,741
2009 Actual	9,188	23,633	770,390	7,005,604	803	713	5,732
2010 Actual	9,324	23,776	817,909	9,233,817	746	675	5,823
2011 Actual	9,241	23,478	825,971	9,274,031	767	681	5,349
2012 Actual	9,041	23,399	788,615	8,978,991	801	676	5,342
2013 Actual	9,081	23,397	760,467	9,053,811	791	660	5,282
2014 Test Year Interrogatory Responses	8,998	23,180	759,070	9,078,743	791	648	5,205
Annual Growth Rate in Usage per Customer/Connection							
2010 Board Approved versus 2010 Actual	(0.5%)	10.3%	(6.0%)	12.6%	7.1%	0.5%	2.2%
2003 Actual							
2004 Actual	(2.6%)	(4.5%)	7.3%		(3.6%)	14.5%	10.3%
2005 Actual	4.7%	2.6%	(0.2%)		(0.2%)	(2.5%)	(12.6%)
2006 Actual	(6.2%)	(2.5%)	(1.9%)		2.7%	(2.6%)	(2.3%)
2007 Actual	0.7%	1.0%	7.7%		1.6%	(1.2%)	3.0%
2008 Actual	(1.7%)	(0.4%)	(6.2%)		(1.6%)	(0.2%)	(3.4%)
2009 Actual	(2.4%)	(4.3%)	(6.3%)		(0.7%)	(3.0%)	(0.2%)
2010 Actual	1.5%	0.6%	6.2%	31.8%	(7.1%)	(5.3%)	1.6%
2011 Actual	(0.9%)	(1.3%)	1.0%	0.4%	2.8%	0.8%	(8.1%)
2012 Actual	(2.2%)	(0.3%)	(4.5%)	(3.2%)	4.4%	(0.6%)	(0.1%)
2013 Actual	0.5%	(0.0%)	(3.6%)	0.8%	(1.3%)	(2.4%)	(1.1%)
2014 Test Year Interrogatory Responses	(0.9%)	(0.9%)	(0.2%)	0.3%	0.0%	(1.8%)	(1.5%)

8.1 EP 30.

Reference: Exhibit 3, Tab 2, Schedule 2

Please update Table 35 to reflect actual data for 2013.

HCHI Response

HCHI has updated Table 35 with 2013 actuals (internally prepared and unaudited).

Table 35
Actual Information for Embedded Distributor – HONI

Year	Customer Number	kWh	kW
2009 (March to December)	8	56,044,835	334,545
2010	8	73,870,537	241,211
2011	8	74,192,250	264,787
2012	8	71,831,928	245,804
2013	8	70,908,989	238,726

8.1 VECC 29.

Reference: E3/T2/S2, page 4

a. **Are the historical customer counts shown in Table 14 year end or average annual values?**

HCHI Response

Customer and connection numbers in Table 14 are year-end numbers as noted in Exhibit 3 / Tab 2 / Schedule 2 / Page 3.

8.1 VECC 30.

Reference: E3/T2/S2, page 4 and page 26
E8/T1/S4, pages 2-3

a. Please describe the supply arrangements for the eight HONI delivery points prior to 2009. In particular were the loads for any of these supply points included in HCHI's purchases from the IESO?

<u>HCHI Response</u>

Refer to the Map of HONI Embedded to HCHI contained in Exhibit 1 Appendix H.

The Jarvis TS 57M1 Embedded Distributor (HONI – Air Products) is a new embedded point as part of the 2010 Cost of Service rate application.

Prior to 2009, the Embedded Distributor points (HONI at Caledonia TS) were subtractive points from the upstream IESO Registered Wholesale Meters. HONI opted to de-register these meter points from the Wholesale market. For this to occur, HCHI agreed to establish an embedded distributor rate class in its 2010 COS rate application.

b. Please confirm that for part of 2009 and thereafter, supply to the eight HONI delivery points was reflected in HCHI's purchases from the IESO.

<u>HCHI Response</u>

HCHI confirms that its actual purchases from the IESO (from a Cost of Power perspective but not from a Load Forecast perspective) since March 2009 to current include supply to seven of the eight HONI delivery points. The eighth point is a wholesale market participant as detailed in Exhibit 1 / Tab 5 / Schedule 6 / Page 2.

c. **Please confirm that for purposes of developing its "billed energy "forecast HCHI assumed that the supply to the eight HONI delivery points was not included in the purchases from the IESO.**

HCHI Response

HCHI confirms that it did not include data for the eight HONI delivery points in the purchases from the IESO for development of its load forecast.

d. **If the historical IESO purchases used in the regression model estimation include deliveries to the eight HONI supply points – please re-do the regression model excluding these values (and any associate losses). Please provide the resulting excel worksheet and the forecast purchase values for 2013 and 2014.**

HCHI Response

Refer to response to VECC IR # 30 c.

8.1 VECC 31.

Reference: E3/T2/S2, pages 7-8

a. Please explain more fully the "manual adjustments" described starting at page 7, line 21. In doing so please provide a schedule setting out the specific adjustments and why they were required.

HCHI Response

HCHI performed a reclassification of its General Service customers in 2012 based on their average demand usage. This caused some customers to be reclassified as General Service Less Than 50 kW and some as General Service 50 to 4,999 kW. The historical usage was adjusted for these customers to accurately forecast load for each customer class based on the existing classification of these customers. The following table provides details of this reclassification:

General Service Reclassification & Adjustment in Load Forecast

Year	General Service Less Than 50 kW			General Service 50 to 4,999 kW		
	Customers	kWh	kW	Customers	kWh	kW
2003	(6)	(261,784)		6	261,784	210
2004	(7)	(643,958)		7	643,958	1,851
2005	(6)	(763,424)		6	763,424	2,127
2006	(7)	(580,308)		7	580,308	1,901
2007	(8)	(654,222)		8	654,222	2,314
2008	(8)	(881,506)		8	881,506	3,148
2009	(7)	(1,165,344)		7	1,165,344	4,202
2010	(6)	(1,476,669)		6	1,476,669	4,859
2011	(5)	(1,222,671)		5	1,222,671	4,133
2012	(4)	(1,172,126)		4	1,172,126	3,860
Totals	(64)	(8,822,012)		64	8,822,012	28,605

The second adjustment in the load forecast model was for services removed in each of 2011 and 2012 actual years but included in the customer count due to accounts not removed from the customer listing. The following table provides details of these removed services:

Removed Services & Adjustment in Load Forecast

	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW
	Customers	Customers	Customers
2011	(23)	(1)	
2012	(23)	(23)	(1)
Totals	(46)	(24)	(1)

The final adjustment was a billing adjustment completed in August 2013 for a Street Lighting account overbilled since April 6, 2009. The number of lights had decreased from 12 to 6 at a flat consumption of 679 kWh and 3.72 kW per month. The number of connections, kWh, and kW were all adjusted in the load forecast model from April 2009 onwards for the Street Lighting rate class.

8.1 VECC 32.

Reference: ***E3/T2/S2, page 10***
2013 Ontario Budget
(http://www.fin.gov.on.ca/en/budget/ontariobudgets/2013/)

a. Please confirm that for purposes of forecasting 2013 and 2014 purchases HCHI held the "Employment" variable constant at the December 2012 value.

HCHI Response

Confirmed.

b. Please provide the actual employment values for 2013 for the months that the data is available (in metrics comparable to those used for 2003-2012 in the regression model).

HCHI Response

The following table provides the 2013 employment variable for the Hamilton-Niagara Peninsula area.

Statistics Canada – Employment Data

2013	Employment Hamilton-Niagara Peninsula (000's)
January	711.2
February	714.4
March	707.1
April	701.4
May	706.8
June	713.7
July	715.8
August	705.1
September	696.6
October	699.3
November	699.4
December	702.3

c. Please revise the forecast for 2013 and 2014 using the forecast employment increases from the 2013 Ontario Budget.

HCHI Response

The employment data from Statistics Canada for the area relevant to HCHI does not show an increase in employment from December 2012 to December 2013 but rather a decrease of 1.5%. HCHI has provided a revised load forecast inclusive of this 2013 actual data, and this continues to be the employment data used for purposes of the updated models.

However, and in response only to this interrogatory, HCHI has also prepared a load forecast model based on the 2013 and 2014 forecast for employment increases from the 2013 Ontario Budget. Refer to excel file entitled “Haldimand_2014_Load Forecast_VECC 32 c_Ontario Budget.xlsx”.

8.1 VECC 33.

Reference: E3/T2/S2, pages 11-12

a. Please provide copies of any reports the OPA has produced regarding HCHI's 2013 CDM program results.

HCHI Response

Refer to the OPA report entitled "Q3 2013 CDM Status Report_Haldimand County Hydro Inc", included as *Appendix A*, issued in mid-December 2013, which provides HCHI's progress as of the end of Q3 2013 using unverified quarterly results for 2013 and final verified results for 2011-12.

b. Please provide a matrix that shows for each year from 2006-2012 the OPA reported in impact of CDM programs in each year, by program year.

HCHI Response

The table below was created using the report "Q3 2013 CDM Status Report_Haldimand County Hydro Inc" and the report "2006-2010 Final OPA CDM Results Haldimand County Hydro Inc." to identify the impact of CDM programs in each year, by program year.

OPA-CDM Reported Results

	CDM Reported Results (Annualized) kWh						
Program Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
2006	1,615,000	1,615,000	1,615,000	1,615,000	281,000	281,000	257,000
2007		2,604,000	2,016,000	1,943,000	1,943,000	838,000	814,000
2008			1,599,000	1,151,000	1,151,000	1,151,000	1,074,000
2009				3,158,000	2,971,000	2,971,000	2,970,000
2010					1,703,000	1,370,000	1,368,000
2011						1,558,701	1,557,464
2012							1,012,284
Total	**1,615,000**	**4,219,000**	**5,230,000**	**7,867,000**	**8,049,000**	**8,169,701**	**9,052,748**

8.1 VECC 34.

Reference: E3/T2/S2, page 14

a. What are the actual 2013 kWh IESO Purchases (netting out purchases related to the HONI supply points as required)?

HCHI Response

The 2013 IESO purchases net of purchases related to HONI supply points are 370,600,657 kWh.

b. Please provide a schedule that sets out:

i) The actual 2013 purchases.
ii) The actual CDD and HDD values for 2013
iii) The assumed weather normal CDD and HDD values
iv) The difference between the Normal and Actual CDD values multiplied by 69,221
v) The difference between the Normal and Actual HDD values multiplied by 11,430
vi) The addition of items (i), (iv) and (v)

HCHI Response

The following table provides the information listed above in i) through to vi).

Purchases	Heating Degree Days ("HDD")	Cooling Degree Days ("CDD")	Weather Normal HDD	Weather Normal CDD	Difference Normal CDD & CDD multiplied by 69,221	Difference Normal HDD & HDD multiplied by 11,430	Total
(i)	(ii)	(ii)	(iii)	(iii)	(iv)	(v)	(vi) = (i) + (iv) + (v)
34,453,934	591.4	-	732.5	0	-	1,612,773.0	36,066,707.0
30,965,647	622.5	-	647.8	0	-	289,179.0	31,254,826.0
31,616,629	535.8	-	541.6	0	-	66,294.0	31,682,923.0
27,694,985	366.5	-	329.3	0.3	20,766.3	(425,196.0)	27,290,555.3
27,052,699	137.7	17.6	165.5	12.9	(325,338.7)	317,754.0	27,045,114.3
28,706,373	41.8	52.4	35.1	55.2	193,818.8	(76,581.0)	28,823,610.8
34,891,029	5.4	84.2	5.5	107.3	1,599,005.1	1,143.0	36,491,177.1
31,944,300	8.2	70.7	11.1	78.7	553,768.0	33,147.0	32,531,215.0
28,067,393	102.0	23.5	71.7	22.3	(83,065.2)	(346,329.0)	27,637,998.8
28,348,884	187.2	0.5	261.1	2.1	110,753.6	844,677.0	29,304,314.6
30,945,091	441.0	-	407.7	0	-	(380,619.0)	30,564,472.0
35,913,695	653.6	-	600.2	0	-	(610,362.0)	35,303,333.0
370,600,659	3,693.1	248.9	3,809.1	278.8	2,069,707.9	1,325,880.0	373,996,246.9

8.1 VECC 35.

Reference: E3/T2/S2, page 15

a. **What was the average total loss factor over the years 2003-2012 used to estimate the regression equation?**

<u>HCHI Response</u>

The average total loss factor for the years 2003 to 2012 is 1.0627.

b. **Please explain why this value was not used to convert the forecast purchases to billed energy.**

<u>HCHI Response</u>

HCHI used the “proposed” loss factor of 1.0663 in its 2014 rate application to convert the forecast purchases to billed energy for the 2014 Test Year. The “proposed” loss factor was determined using the Board approved 5-year (2008 to 2012) historical average calculation, and has now been updated to include 2013 actual (2009 to 2013), which results in a revised “proposed” loss factor of 1.0655 and when approved, will be the loss factor HCHI uses to bill its customers effective May 1, 2014. It seems only reasonable to calculate a forecast billed energy load based on a loss factor that HCHI will be utilizing to bill with during the same period. This is the same methodology approved in HCHI’s 2010 COS (EB-2009-0265).

8.1 VECC 36.

Reference: E3/T2/S2, page 23

a. **Please confirm that the CDM variable used to forecast 2014 purchases included the full annual savings in 2014 from 2012 CDM programs.**

HCHI Response

Confirmed.

b. **If this is the case, why is it necessary to further adjust the 2014 forecast for ½ of the 2012 program savings persisting in 2014.attributable to projected purchases for provide the actual billed energy by class for 2013.**

HCHI Response

In response to this interrogatory, HCHI has now removed the 2012 program savings persisting in 2014. All updated tables and models that accompany these responses have been revised accordingly.

c. **Please reconcile HCHI's proposal to include ½ of the 2012 program savings in its manual CDM adjustment with the Board's Decision regarding Sioux Lookout's 2013 Rates (EB-2012-0165, page 7) that it should be excluded.**

HCHI Response

Refer to response in b.

8.2 Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?

8.2 Staff 31. Cost Allocation Model

Reference: Cost Allocation Model Sheet O2

Board staff notes that there are errors in Excel row 163. Please review and correct.

HCHI Response

In the Board's Cost Allocation Model on Sheet "O2 Fixed Charge/Floor/Ceiling", row 163 is linked to row 147 on Sheet "I3 TB Data" which is a blank row. HCHI's final Cost Allocation model had formulas on Sheet O2 linked to Sheet "O5 Details by Class & Accounts" which is incorrect. HCHI has now corrected this by deleting these formulas on Sheet O2 since row 147 on Sheet I3 remains a blank row in HCHI's Cost Allocation model.

HCHI has also corrected the formula on Sheet O2 for the Embedded Distributor - HONI customer rate class which was incorrectly linked to the wrong row on Sheet O5. The total Meter Capital in account 1860 on Sheet O2 was not adding to the total Meter Capital in 1860 on Sheet I3. This formula is also incorrect in the Board's blank Cost Allocation model, "2014_Cost_Allocation_Model_V3.1".

8.2 Staff 32. Load Profiles

Reference: Exhibit 7 Tab 1 Schedule 3 Cost Allocation Updates
Exhibit 3 Tab 2 Schedule 2 Adjustments to Classes

In describing the cost allocation updates, HCHI state that it has scaled the load profile previously generated by HONI on behalf of HCHI using scaling factors that it calculates in Table 5. In describing the adjustments to the class data for developing the load forecast in Exhibit 3 Tab 2 Schedule 2, HCHI state that it made manual adjustments to the Residential, General Service Less Than 50 kW, and General Service 50 to 4,999 kW rate classes for services removed in 2011 and 2012 and for reclassifications between the two General Service classes.

a. Were there any similar adjustments made to the load profiles for the purposes of cost allocation?

<u>HCHI Response</u>

No, HCHI did not make any adjustments to the 2004 Weather Normal Values provided by HONI in HCHI's original 2007 cost allocation informational filing.

b. If there were no adjustments, please revise the load profiles accordingly.

<u>HCHI Response</u>

HCHI has now revised the load profiles from 2004 to incorporate the manual adjustments to class data completed in the 2014 load forecast. The following table is an update to Exhibit 7 / Tab 1 / Schedule 3 / Table 5:

Table 5
Load Profile Scaling Percentages

Customer Class	2004 Weather Normal Values (kWh)	2014 Weather Normal Values (kWh)	Scaling Percentage
Residential	184,896,586	168,256,471	91.00%
General Service Less Than 50 kW	55,682,191	53,569,663	96.21%
General Service 50 to 4,999 kW	141,297,466	119,035,699	84.24%
Street Lighting	2,263,805	2,355,438	104.05%
Sentinel Lighting	600,812	320,970	53.42%
Unmetered Scattered Load	539,838	350,485	64.92%
Embedded Distributor - Hydro One Networks Inc.	65,305,781	72,629,941	111.22%

Note: Embedded Distributor 2004 kWh are for Norfolk Power Distribution Inc.

8.2 Staff 33. Embedded Class

Reference: Exhibit 7 Tab 1 Schedule 3 Embedded Distributor – Hydro One Networks Inc.
Cost Allocation Model

The allocation of costs to the Embedded Class is explained as a combination of energy consumption (kWh) and length (km). All other classes are based on allocations using peak and minimum plant.

a. When HCHI says “allocated”, does it mean that these factors were used to develop the directly assigned costs on tab I3 Trial Balance Data of the Cost Allocation Model?

HCHI Response

HCHI has followed the same methodology used to develop the Embedded Distributor customer rate class in HCHI’s 2010 COS in deriving the costs associated with this class in the 2014 COS. HCHI has used an Excel model similar to Board’s Appendix 2-Q to directly assign the costs on the Sheet “I9 Direct Allocation” and on Sheet “I3 TB Data” in the Board’s Cost Allocation model.

Staff IR # 36 refers to the Board’s Decision and Order issued December 19, 2013, EB-2013-0141, approving HONI Sub-transmission rates (“ST rates”) effective January 1, 2014. In conjunction with updating HCHI’s Low Voltage charges and Retail Transmission Service Charges in response to Staff IR # 36 a. and b., HCHI has also updated the costs attributable to the Embedded Distributor customer rate class. Refer to response to EP IR # 6 b. These costs form part of the directly assigned costs in the Cost Allocation model to the Embedded Distributor.

HCHI has provided its worksheet in Excel format, “Wheeling Charge Calculation_Embedded Distributor – Hydro One_20140304”, that supports the direct allocation of costs in the Cost Allocation model for the Embedded Distributor.

b. Please explain the theoretical reason for this deviation from the Board's model of using specifically defined peak demand allocators based on coincident and non- coincident peaks rather than kWh and km.

HCHI Response

The 2004 Weather Normal Values provided by HONI for the load profiles used in the 2007 Cost Allocation Informational Filing included the Embedded Distributor – Norfolk Power Distribution Inc. ("NPDI"). The embedded situation with HONI did not exist at that time. HCHI feels that in order to update the Embedded Distributor rate for HONI, the better method is to update the directly allocated costs utilizing the same format that developed the original rate than to scale HONI's load against the NPDI load. For this reason, HCHI did not include specifically defined peak demand allocators based on coincident and non-coincident peaks.

c. Is the peak data available to use in developing the costs for the Embedded Class?

HCHI Response

Refer to response to Staff IR # 33 b.

d. If the peak data is available, please directly assign costs using peak data as it is used in the model. The allocation should be based on any updates from the interrogatories of related data that have an effect on inputs to the model, such as forecast demand and load profiles.

HCHI Response

Refer to response to Staff IR # 33 b.

8.2 Staff 34. Street Lighting

Reference: Cost Allocation Model Sheet I6.2 Customer Data Worksheet

On Sheet I6.2 for street lighting, there are 2,979 Devices and 1,469 connections. This suggests that one connection serves two devices. If this observation of 2:1 fixture: connection ratio is incorrect please explain the wiring configurations and how they relate to the factors.

<u>HCHI Response</u>

HCHI provides maintenance services to the municipality (Haldimand County) for streetlight services. Haldimand County owns the streetlight assets. HCHI has provided assistance to Haldimand County in developing the Streetlight Design Guidelines.

Generally the rural area streetlights are connected in the configuration of Diagram 1. The urban areas have streetlights connected in the configuration of Diagram 2.

Diagram 1

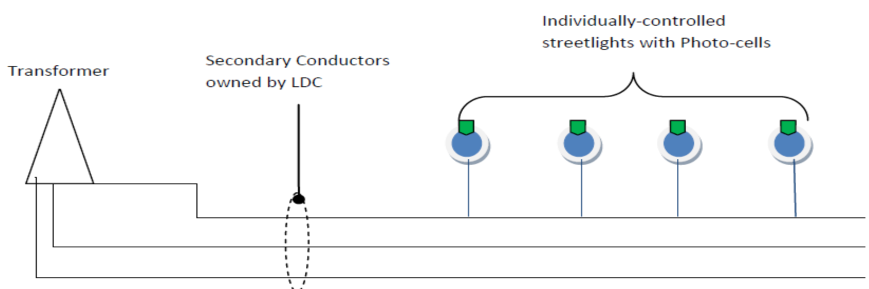


Diagram 2

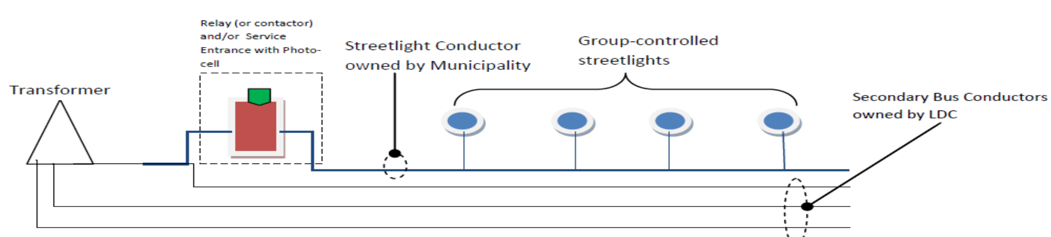


Figure 11 - Group-controlled Streetlight Circuit

Source of Diagrams 1 & 2 http://www.esasafe.com/assets/files/esasafe/pdf/Guideline_for_Street_Lighting_Assets.pdf

HCHI reported in its 2010 Cost of Service Electricity Distribution Rate application 2,879 Fixtures and 1,610 Connections (1.8:1 ratio). The average connection ratio identified on Sheet I6.2 is correct at 2:1.

HCHI has a large rural territory where distances are great such that streetlights cannot be ‘daisy chained’ or connected to the same streetlight circuit. HCHI has made efforts to ensure that when maintenance occurs that a streetlight connection is made to the streetlight bus system where it exists. These efforts have resulted in the ratio improving from 2010.

8.2 Staff 35. Revenue to Cost Ratios ("R:C ratio")

Reference: Appendix 2-P

HCHI is proposing to move GS 50 – 4,999 kW class to a R:C ratio to 106% from 113%. HCHI is also proposing to set the residential class R:C ratio to 100%.

a. What factors did HCHI consider in its decision to propose to use these R:C ratios?

HCHI Response

As further explained in Exhibit 7 / Tab 1 / Schedules 1 and 4, the overriding factors that HCHI considered in its decision to propose the revenue-to-cost ("R:C") ratios may be summarized as follows:

- The pace at which R:C ratios should be adjusted to a Board-approved ratio should only be affected by concerns regarding its impact on any rate classes; and
- Movements of R:C ratios closer to one is supported by improved cost allocations.

b. What steps did HCHI take to solicit customer feedback for these proposals?

HCHI Response

HCHI did not take any steps to solicit customer feedback for these proposals as the total bill impact for the Residential customer rate class remained at a decrease and it was a benefit to the General Service 50 to 4,999 kW customer rate class as the over-contributing class. The posting of HCHI's Notice of Application in local newspapers and on its website and Twitter account did not generate any customer comments.

8.2 EP 31.

Reference: Exhibit 7, Tab 1, Schedule 4

Please consider the following scenario with respect to the 2014 proposed revenue to cost ratios. First, move the GS > 50 class down to 120%, the sentinel class up to 80% and the embedded distributor class up to 80%.

a. With no changes to the other rate classes, what is the resulting revenue shortfall of the changes noted above?

<u>HCHI Response</u>

This would result in a revenue sufficiency, and not a shortfall, in the amount of $61,000.

b. In order to recover the revenue shortfall identified in part (a) above, please increase the rate classes with the lowest revenue to cost ratios up to the next highest and so on, until the revenue shortfall has been collected. As an example, with the embedded distributor and sentinel lighting starting at 80%, increase those two classes to the next highest of 80.63% for unmetered loads, and then increase these three classes until they reach the next highest, being 86.31% for street lighting, and so on, until the revenue requirement is recovered in full.

<u>HCHI Response</u>

Based on the response to a., and largely due to not reducing the GS 50 to 4,999 kW class as HCHI is proposing, this results in an even larger revenue sufficiency.

Based on the above process, please provide the 2014 proposed ratios.

<u>HCHI Response</u>

Refer to response in b.

c. **Please repeat the exercise in part (b), but with a change in the revenue to cost ratio for the embedded distributor class from 80% as noted in the pre-amble to 100%.**

HCHI Response

In response to this interrogatory in its entirety, HCHI has decreased the proposed revenue to cost ratio for the Embedded Distributor class to 100%, with the resulting change impacting the GS 50 to 4,999 kW class. All updated tables and models that accompany these responses have been revised accordingly.

8.2 VECC 37.

Reference: ***E7/T1/S3, page 2***
Cost Allocation Model, Sheet I9

a. Are any General Plant costs directly assigned to the Embedded Distributor class?

- **i) If yes, how were the costs to be assigned determined?**
- **ii) If no, 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.**

HCHI Response

HCHI has not directly assigned any General Plant costs to the Embedded Distributor – HONI class.

However, the Board's Cost Allocation model has assigned some General Plant costs to the Embedded Distributor – HONI class as found on Sheet "O5 Details by Class & Accounts" using the same allocator as the balance of HCHI's customer classes, Net Fixed Assets Excluding Capital Contribution ("NFA ECC").

b. **Are any General and Administration costs directly assigned to the Embedded Distributor class?**

   i) **If yes, what accounts' costs were directly allocated and which ones were not? Also, how were the costs to be assigned determined?**

   ii) **If no, 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.**

HCHI Response

HCHI has assigned General and Administration costs directly to the Embedded Distributor – HONI class as illustrated in the Excel file "Wheeling Charge Calculation – Embedded Distributor – Hydro One_20140304", tab "Cost Allocation-OM&A (AirProd)" submitted in response to Staff IR # 33 a.

c. **Were any Services costs either directly assigned or allocated to the Embedded Distributor class?**

HCHI Response

No service costs were allocated to the Embedded Distributor – HONI class.

8.2 VECC 38.

Reference: E7/T1/S4, page 2

a. Please explain why the ratios for Street Lighting and USL – which are currently less than Residential's – are both held constant whereas the ratio for Residential is increased?

HCHI Response

In conjunction with HCHI's 2010 Cost of Service, these two rate classes were both adjusted in accordance with Board direction and experienced significant rate increases as a result. Both rate classes are within the Board-Approved revenue to cost ratio range. HCHI was able to move the Residential to 100% without significant bill impact.

b. Why is it appropriate to increase the ratio for the Embedded Distributor from below to above 100%?

HCHI Response

Refer to response to EP 31 c.

8.3 Is the proposed rate design including the class-specific fixed and variable splits and any applicant-specific rate classes appropriate?

8.3 EP 32.

Reference: Exhibit 8, Tab 1, Schedule 2

a. Based on the response to 8.2-Energy Probe-31 to each of parts (b) and (c), please provide a version of each of Table 5 and Table 6 that shows the proposed monthly service charges.

HCHI Response

These tables are not being provided due to the results in response to EP IR # 31.

b. Based on the response to 8.2-Energy Probe-31 to each of parts (b) and (c) and to part (a) above, please provide the rate and bill impacts shown in Exhibit 8, Tab 4, Schedule 1 (Appendix 2-W).

HCHI Response

Refer to updated Appendix 2-W.

8.3 VECC 39.

Reference: E8/T1/S2, page 3

a. **Why is it appropriate to increase the fixed charge for USL when it is already above the Board's ceiling value?**

HCHI Response

This was required in order to maintain the current fixed/variable split.

8.4 Are the proposed Total Loss Adjustment Factors appropriate for the distributor's system and a reasonable proxy for the expected losses?

HCHI Note

There were no interrogatories filed with respect to this issue.

8.5 Is the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates appropriate?

8.5 Staff 36. Retail Transmission Sales Rates

Reference: ***Exhibit 8 Tab 1 Schedule 3 Low Voltage Charges***
Exhibit 8 Tab 1 Appendix A – RTSR Work Form

On December 19, 2013, the Board issued its decision in EB-2013-0141 approving new HONI Sub-transmission rates ("ST rates"). On January 9, 2014, the Board issued its decision in EB-2012-0031 approving new Uniform Transmission Rates (UTRs)

a. Please update the Low Voltage charges based on the new ST rates.

HCHI Response

HCHI has updated the Low Voltage charges to its Regular customers and the low voltage charges applicable to the Embedded Distributor (refer to EP IR # 6 b. and Staff IR # 33 a.) based on the approved HONI Sub-transmission rates effective January 1, 2014.

b. Please update the Retail Transmission Service Rates based on the new UTRs.

HCHI Response

HCHI has updated its Retail Transmission Service Rate models for its Regular customer classes and its Embedded Distributor customer class. Refer to Excel models "Haldimand_2014 RTSR MODEL_Regular Customers_20140304" and "Haldimand_2014 RTSR MODEL_Embedded Distributor_20140304".

8.5 Staff 37. RTSR Harmonization

Reference: Exhibit 8 Tab 1 Schedule 3 Harmonization of GS 50 – 4,999 RTSR

HCHI is proposing to harmonize its RTSR for those GS>50kW customers with and those without interval meters. Please demonstrate and explain the development of the harmonized rates using the new EB-2012-0031 UTRs issued on January 9, 2014.

HCHI Response

The harmonized Retail Transmission Service Rates ("RTSRs") for the General Service 50 to 4,999 kW customer rate class, Interval metered and Non-Interval metered, was derived using the 2012 actual billed / unbilled demand (kW) data and HCHI's May 1, 2013 approved RTSRs for these two sub-classes of customers. HCHI weighted each of the two sub-classes calculated total billed RTSR for both Network and Connection. The harmonized rates for each of Network and Connection were a calculation on total charges divided by total demand respectively. The following table provides these calculations:

General Service 50 to 4,999 kW Customer Rate Class
Harmonization of Retail Transmission Service Rates

Retail Transmission Network Service Rate	2012 Demand kW Billed / Unbilled	May 1, 2013 Rate	Total Calculated Charges	Harmonized Rate RTSR-Network
General Service 50 to 4,999 kW - Non - Interval Metered	91,666	$ 2.3783	$ 218,009.25	
General Service 50 to 4,999 kW - Interval Metered	240,823	$ 2.5228	607,548.26	
	332,489		$ 825,557.51	$ 2.4830
Retail Transmission Connection Service Rate	**2012 Demand kW Billed / Unbilled**	**May 1, 2013 Rate**	**Total Calculated Charges**	**Harmonized Rate RTSR-Connection**
General Service 50 to 4,999 kW - Non - Interval Metered	91,666	$ 1.7325	$ 158,811.35	
General Service 50 to 4,999 kW - Interval Metered	240,823	$ 1.9149	461,151.96	
	332,489		$ 619,963.31	$ 1.8646

HCHI did not originally use the Uniform Transmission Rates ("UTRs") to harmonize its existing RTSRs and therefore has not provided an updated calculation with regards to using the new UTRs issued January 9, 2014.

8.5 VECC 40.

Reference: E8/T1/S3, pages 1-2

a. Please indicate what the measurement interval is for determining billing kW for the interval metered and non-interval metered customers respectively (i.e. is it 15 minutes, 20 minutes, 60 minutes or some other value)?

<u>HCHI Response</u>

The measurement interval for determining billing kW for both General Service 50 to 4,999 kW Non-Interval and General Service 50 to 4,999 kW Interval customers is 15 minute peak demands.

b. If the measurement intervals are not the same, then – if the rates are harmonized - won't the customer's class with the shorter interval be paying relatively more for Retail Transmissions service even if their loads are exactly the same as those customers in the other class?

<u>HCHI Response</u>

Response not required based on response in a.

8.5 VECC 41.

Reference: E8/T1/S3, page 3

a. Please update the proposed RTSRs for the 2014 approved UTRs and approved HON ST rates.

HCHI Response

Refer to Staff IR # 36 a. and b.

8.5 VECC 42.

Reference: E8/T1/S3, page 6

a. **Please update Table 11 to reflect HONI's approve 2014 rates and actual demand from January to December 2013.**

<u>HCHI Response</u>

HCHI has updated Table 11 with HONI's approved Sub-transmission rates effective January 1, 2014 and actual demand for the period January to December 2013.

Table 11
Forecast Low Voltage Cost for 2014 Test Year

HONI Sub-Transmission ("ST") Charge Types	HONI 2014 ST Rates	Billing Determinant Demand (kW)	Months	Low Voltage Dollars
Monthly Service Charge (6 Points)	$ 298.89		72	$ 21,520
Meter Charge (2 DS's)	$ 476.35		24	$ 11,432
Low Voltage Charges - LVDS	$ 1.987	23,293		$ 46,283
Common ST Lines - TS	$ 0.682	60,780		$ 41,452
Volumetric Rate Riders	$ 0.307	60,780		$ 18,659
Adjustment for Long-term Load Transfers				$ 597
Total Low Voltage Costs to be Allocated				$ 139,943

8.6 Is the proposed Tariff of Rates and Charges an accurate representation of the application, subject to the Board's findings on the application?

HCHI Note

There were no interrogatories filed with respect to this issue.

9 Accounting

9.1 Are the proposed deferral accounts, both new and existing, account balances, allocation methodology, disposition periods and related rate riders appropriate?

9.1 Staff 38. Account 1518

Reference: Exhibit 9 Tab 2 Schedule 1 Table 5 Retail Service Charge Variance (1518) and Account 5340 Retail Settlement Services balance

HCHI shows in Table 5 that the costs related to Retail Services are approximately four times the revenues from Retail Service Charges for 2012 Actual, 2013 Bridge year, and 2014 Test year.

a. What portion of the expenses shown on Table 5 is related to non-retailer customers of Haldimand?

HCHI Response

No portion of the expenses detailed in Table 5 (1518) represent costs associated with non-retailer customers.

b. Account 5340 Retail Settlement Services shows an expense of $78,601 for 2012. The account balance reported to the Board under RRR 2.1.7 for this account for 2012 was $65,506.

i. Please explain the discrepancy from RRR 2.1.7 for 2012 for this account.

HCHI Response

Account 5340 in Table 5 shows a balance of $78,601 and in Table 6 a balance of $1,604 for a total $80,205 allocated costs to retailer enrolled customers. The actual total incurred costs for HCHI for 2012 to account 5340 are $147,430; $80,205 attributed to enrolled customers and $67,225 attributed to non-retailer enrolled customers. The under recovery from the Retailer revenue of $80,241 (1518) and $1,683 (1548) or the total variance entry for these two accounts of $81,924 has been recorded as an offset to account 5340 resulting in the reported total of $65,506 under RRR 2.1.7.

ii. **Please provide a description and breakdown of the types of expenses recorded in this account.**

<u>HCHI Response</u>

HCHI only records costs associated with retailer enrolled customers in account 1518. Costs that are attributable to all customers are allocated each month based on the number of enrolled customers to the total customers for the month. Types of expenses recorded each month to this account are meter reading for enrolled customers, the fee associated with the hub services for enrolled customers, the Retail Settlement Clerk position on account of contract administration and monitoring and the retail settlement process with the Retailers, billing and collection costs associated with enrolled customers, the interest payable on Retailer security deposits, the wire service charges associated with payments to the Retailers, and a portion of the annual bank service charge on account of the Letter of Credit with the IESO.

c. **Given that the expenses are material and are approximately four times the revenues for Retail Services, why are the charges not included in OM&A?**

<u>HCHI Response</u>

It is HCHI's understanding that incremental costs associated with providing services to retailer enrolled customers and the Retailers themselves were to be tracked against the revenue associated with recovering those costs and tracked in the two respective variance accounts, 1518 and 1548. The under contribution from the Retailer revenue has existed since market opening in 2002. The variance accounts are disposed of with each cost of service rate application and the differences collected from all customers by way of a rate rider once disposition has been approved of from the Board.

9.1 Staff 39. Accounts 1531 and 1532

Reference: Exhibit 9 Tab 2 Schedule 1 Accounts 1531 and 1532

HCHI states that "With this Application, HCHI is requesting approval to record forecast capital renewable connection investments for the period 2015 to 2018 into this account…" [emphasis added].

a. Please clarify and confirm that only actual expenditures will be recorded in the deferral account requested for Renewable Connection Capital Deferral Account.

HCHI Response

HCHI will only be recording the actual capital renewable connection investments incurred for the period 2015 to 2018 into account 1531.

b. Please describe how the underlying capital and OM&A amounts would be tracked and calculated.

HCHI Response

HCHI has requested approval to record Renewable Energy Generation ("REG") capital investments into deferral account 1531, Renewable Connection Capital. HCHI will only record actual capital costs incurred into this account and will track the direct benefit portion separate from the provincial recovery portion through the use of sub-accounts of account 1531.

The direct benefit portion for REG capital spend for the period commencing January 1, 2015 through to December 31, 2018 will be calculated in accordance with section 79.1 of the OEB Act and Regulation 330/09 under the OEB Act assumed as 17% for REG expansion investments and 6% for REG enabling improvement investments, both recorded into a sub-account of account 1531. The direct benefit portion of the REG capital spend that occurred in the 2013 Bridge Year and has been forecast for the 2014 Test Year has been included in HCHI's regular capital spend using the half-year rule and forming part of the Fixed Asset Average Net Book Value for the 2014 Test Year. The capital spends for 2013 and 2014 have been and will be recorded directly to the capital series of accounts as designated by the OEB's Accounting Procedures Handbook ("APH").

The Provincial benefit portion of the capital spend for the 2013 Bridge Year, 2014 Test Year, and the forecast years of 2015 through to 2018 inclusive will be recorded in a separate sub-account of 1531 as part of the proposed request for recovery submitted with this application. As the actual capital spend occurs, HCHI will record 83% of REG expansion investments and 94% of REG enabling improvement investments into the relative sub-accounts.

HCHI has also requested with this application a REG Funding Adder calculated on the revenue requirement for the REG capital spend for the direct benefit portion of the forecast years of 2015 through to and including 2018 to be recorded to a sub-account of account 1533, Renewable Generation Connection Funding Adder Deferral Account. HCHI has requested this funding adder to have an effective date of May 1, 2014, to commence with the approval of the rest of the rates requested as part of this application. The funding adder has been calculated to be effective until April 30, 2019 coinciding with HCHI's expected next cost of service rate application and the end of the forecasted REG capital spend and calculated revenue requirement. At that time, HCHI will request for disposition of these REG capital accounts and the offsetting revenue collected through the funding adder.

HCHI will also record and track separately in a sub-account of 1533 the provincial recovery portion revenue requested as part of this application.

Carrying charges will be applied to all sub-accounts of 1531 and all sub-accounts of 1533 and calculated in accordance with the OEB's APH.

Refer to Exhibit 2 / Tab 5 and Exhibit 9 / Tab 5 for the detailed amounts and calculations of the direct benefit and provincial recovery portions related to the REG capital spend, calculated revenue requirements, and funding adder request.

9.1 Staff 40. Account 1576

Reference: Exhibit 9 Tab 2 Schedule 4 Table 15

Haldimand has not allocated disposition of account 1576 to its embedded distributor.

a. Please provide the rationale for excluding Hydro One, the embedded distributor from disposition of account 1576.

HCHI Response

HCHI excluded the Embedded Distributor – HONI customer rate class from the disposition of account 1576 based on the insignificant percentage allocation of assets and amortization expense attributable to this rate class. Only a total of 0.45% of capital accounts 1830, 1835, and 1860, and 0.65% of total amortization expense are attributable to the Embedded Distributor - HONI customer rate class.

b. Provide an alternative calculation for the rate rider including allocation to the embedded distributor rate class.

HCHI Response

HCHI has recalculated the rate rider for account 1576 Accounting Changes under CGAAP inclusive of the Embedded Distributor customer rate class. The recalculated rate rider does not include any changes as a result of responses to these IRs in order to provide a comparison to the original rate riders exclusive of the Embedded Distributor - HONI class. The following table provides these calculations and includes the rate rider submitted with the original application for comparison purposes.

Account 1576 Rate Rider Calculations

			Property, Plant, & Equipment ("PPE") Adjustment - Account 1576			BILLING UNITS (2014)		"REVISED" RATE RIDER (FIVE YEARS)	"ORIGINAL" RATE RIDER (FIVE YEARS)
RATE CLASS	Proposed Net Revenue Allocation	Distribution Revenue	PPE Adjustment in Account 1576	Rate of Return	Total			PPE Adjustment Rate Rider $ / unit	PPE Adjustment Rate Rider $ / unit
Residential	8,717,101	69.13%	$ (1,009,092)	$ (274,977)	$ (1,284,069)	168,256,471	kWh	$ (0.0015)	$ (0.0016)
General Service Less Than 50 kW	1,666,279	13.21%	$ (192,825)	$ (52,545)	$ (245,370)	53,569,663	kWh	$ (0.0009)	$ (0.0009)
General Service 50 to 4,999 kW	1,410,243	11.18%	$ (163,194)	$ (44,470)	$ (207,664)	334,274	kW	$ (0.1242)	$ (0.1280)
Street Lighting	315,301	2.50%	$ (36,493)	$ (9,944)	$ (46,437)	6,564	kW	$ (1.4149)	$ (1.4578)
Sentinel Lighting	114,609	0.91%	$ (13,283)	$ (3,620)	$ (16,903)	892	kW	$ (3.7899)	$ (3.8993)
Unmetered Scattered Load	17,438	0.14%	$ (2,044)	$ (557)	$ (2,601)	350,485	kWh	$ (0.0015)	$ (0.0015)
Embedded Distributor - Hydro One	369,483	2.93%	$ (42,769)	$ (11,655)	$ (54,424)	227,715	kW	$ (0.0478)	$ -
Total	12,610,454	100.00%	$ (1,459,700)	$ (397,768)	$ (1,857,468)				

9.1 Staff 41. LRAMVA

Reference: Exhibit 9 Tab 6 Schedule 2 LRAMVA

HCHI has requested to dispose of its LRAMVA balance of $83,818 (including $1,611 in carrying charges) as a debit to customers from Account 1568. The lost revenues are the result of CDM savings from programs delivered in 2011 and 2012.

a. Please discuss how HCHI allocated its verified 2011 program savings in Table 25 to the GS<50 kW and GS 50-4,999 kW rate classes from the following programs:
- **Business Program – Efficiency: Equipment Replacement**
- **Business Program – New Construction and Major Renovation Incentive**
- **Pre-2011 Programs completed in 2011 – Electricity Retrofit Incentive Program**
- **Pre-2011 Programs completed in 2011 – High Performance New Construction**

HCHI Response

The specific allocation to rate class, by initiative, is presented in Table B-1 and Table B-2 of the report entitled "*Haldimand County Hydro 2011-2012 LRAMVA*" (the "IndEco report"). Where the allocation is 100% to a specific rate class, that reflects the type of customers targeted by the initiative within HCHI's service territory. Where the allocation is not all to one rate class, HCHI's CDM staff allocated based on their professional judgement and awareness of installations within HCHI's service territory.

b. Please discuss how HCHI calculated the 2011 peak demand (kW) savings attributable to its Business, Industrial and Pre-2011 Programs. Within your response, discuss how HCHI determined what multiplier it would use to translate the monthly peak demand savings it received from the OPA.

HCHI Response

The measures implemented as part of the Business and Industrial programs within HCHI's service territory are primarily measures that affect the base load use of equipment during normal business hours, so those would reduce customer's monthly peak by the same amount as shown by the OPA for peak reductions. Billing is monthly, so a factor of 12 is used to convert the annual numbers into monthly numbers. This is as described in the Notes to Tables B-3 and B-4 of the IndEco report.

c. Please discuss how HCHI allocated its verified 2012 program savings in Table 26 to the GS<50 kW and GS 50-4,999 kW rate classes from the following programs:

- **Business Program – Efficiency: Equipment Replacement**
- **Business Program – New Construction and Major Renovation Incentive**

HCHI Response

The specific allocation to rate class, by initiative, is presented in Tables B-1 and B-2 of the IndEco report. Where the allocation is 100% to a specific rate class, that reflects the type of customers targeted by the initiative within HCHI's service territory. Where the allocation is not all to one rate class, HCHI CDM staff allocated based on their professional judgement and awareness of installations within HCHI's service territory.

d. Please discuss how HCHI calculated the 2012 peak demand (kW) savings attributable to its Business and Industrial programs. Within your response, discuss how HCHI determined what multiplier it would use to translate the monthly peak demand savings it received from the OPA.

HCHI Response

The measures implemented as part of the Business and Industrial programs within HCHI's service territory are primarily measures that affect the base load use of equipment during normal business hours, so those would reduce customer's monthly peak by the same amount as shown by the OPA for peak reductions. Billing is monthly, so a factor of 12 is used to convert the annual numbers into monthly numbers. This is as described in the Notes to Tables B-3 and B-4 of the IndEco report.

e. Please discuss why HCHI does not feel that Demand Response 3 Program results contribute to lost revenues. If available, please provide any supporting documentation it has received from the OPA confirming this position.

<u>HCHI Response</u>

The OPA provides HCHI with its Conservation and Demand Management Status Report with two scenarios. Scenario One assumes that Demand Response will persist for one year; and Scenario Two assumes that Demand Response will persist until the end of 2014.

Given the uncertainty of persistence beyond one year, HCHI has taken the approach of one year persistence.

The following is an excerpt from HCHI's OPA reporting information describing Scenario One and Two:

saveONenergy

Ontario Power Authority
Conservation & Demand Management Status Report
Q3 2013 Preliminary Results Update
Haldimand County Hydro Inc.

Unverified OPA-Contracted Province-Wide CDM Program Progress at a Glance

Unverified Progress to Targets	Incremental Q3-2013	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	0.1	0.7	23%	0.8	27%	37
Net Energy Savings (GWh)	0.0	10.0	75%	10.0	75%	31

Program-to-Date towards Target: Combination of verified (2011-12) and unverified (2013) results. To align with savings counted towards OEB targets, peak demand is represented by annual savings in 2014 and energy is represented by the cumulative savings from 2011-2014.

Scenario 1: Assumes that demand response resources have a persistence of 1 year. Official reporting policy for demand response resources.

Scenario 2: Assumes that demand response resources remain in your territory until 2014. Used to better assess progress towards demand targets.

Rank: Sorts each LDC by % of peak demand or energy target achieved as of the current reporting period using Scenario 2.

9.1 EP 33.

Reference: Exhibit 9, Tab 5, Schedule 4

a. Please confirm that the revenue requirements shown for 2015 through 2018 in Table 22 do not include any revenue requirement associated with the 2014 REG investments, as these costs will already be built into base rates. If this cannot be confirmed, please explain why the rate adder in 2015 through 2018 should include the recovery of costs already built into base rates in 2014.

HCHI Response

HCHI confirms that Exhibit 9 / Tab 5 / Schedule 4 / Table 22 does not include any revenue requirement associated with the 2014 Renewable Energy Generation ("REG") investments.

b. Please explain why the rate adder shown in Table 23 is shown as being in place for 5 years rather than for 2015 through 2018.

HCHI Response

HCHI is proposing to commence charging the REG Funding Adder with approval of its May 1, 2014 rates which make it in place for 5 rate years. If the REG Funding Adder is approved to commence May 1, 2015, then the adder will need to be recalculated.

9.1 EP 34.

Reference: Exhibit 9, Tab 5, Schedule 4 &
Exhibit 1, Tab 5, Schedule 2 &
Exhibit 2, Tab 6, Schedule 1

The evidence in the first reference shows the calculation of a rate adder in Table 23 for the years 2015 through 2018. The evidence in paragraph 10 in the second reference requests that the funding adder be effective May 1, 2014. In the third reference, HCHI indicates that it is proposing direct benefit recovery from its own customers for the years 2015 through to and including 2018 as a funding adder. Please reconcile.

HCHI Response

The capital spend would occur for the period January 1, 2015 through to December 31, 2018 inclusive with recording in the variance account 1531. HCHI has requested the REG Funding Adder for collection of this revenue requirement to commence May 1, 2014 effective until April 30, 2019 at which time HCHI will be going through its next rebasing with request to dispose of the variance account and offsetting revenue collected.

9.1 VECC 43.

Reference: E1/T1/S10 & E9/T5/S1

Renewable Energy Generation Deferral Account

a. Please explain why HCHI is proposing to record the direct benefits of its REG capital for 2013 and 2014 to regular capital program, but believes it appropriate to record the direct benefits subsequent to 2014 in the deferral account.

HCHI Response

It is HCHI's understanding that the 2013 and 2014 direct benefit capital spends become part of the 2014 Test Year rate base.

b. Please provide the basis for the 17% and 6% direct benefit allocations.

HCHI Response

The Provincial Benefit calculations were determined as per the *Report of the Board EB-2009-0249 Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09,* which referenced HONI applications for 2010 and 2011 distribution rates where it states: *"those dollar amounts represent 6% for REI investments and 17% for Expansion investments"*.

Also, refer to Staff IR # 23.

9.1 VECC 44.

Reference: E2/T4/S1/pg.2 & E9/T3/S1/pg.2

Stranded Meters

a. **Please explain why there was an increase in the gross asset value of stranded meters between 2009 and 2012. Specifically, it appears that HCHI was installing (or adding to) standard meters during the period it was installing smart meters.**

HCHI Response

HCHI began installing smart meters in 2009 and continued in 2010, 2011, and until complete in 2012. The conventional meters did not become stranded until they were removed from service. The Gross Asset Value increased as the meters were removed until all smart meters were installed in 2012.

b. **Please explain the methodology used to track meters to the individual rate class, specifically address what costs were tracked for each individual customer.**

HCHI Response

HCHI identified each removed meter by meter number, meter type, account classification, installation date and meter cost. Each meter was amortized over 25 years. Meter costs were totaled based on the account classification that the meter was associated with.

c. **Prior to the smart meter program did HCHI install the same meters for both residential and GS<50 customers?**

HCHI Response

Yes, HCHI installed the same meters for both Residential and GS<50 customers if they were the same service type. For example, a single phase 200 amp service for a Residential or GS<50 kW customer would receive the same meter. A single phase 400 amp service would require a transformer rated meter but the same meter would be installed for a Residential single phase 400 amp service and a GS<50 kW single phase 400 amp service.

9.2 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified, and is the treatment of each of these impacts appropriate?

HCHI Note

There were no interrogatories filed with respect to this issue.

END OF DOCUMENT

Ontario Power Authority
Conservation & Demand Management Status Report

Q3 2013 Preliminary Results Update

Haldimand County Hydro Inc.

Unverified OPA-Contracted Province-Wide CDM Program Progress at a Glance

Unverified Progress to Targets	Incremental Q3-2013	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	**0.1**	**0.7**	23%	**0.8**	27%	**37**
Net Energy Savings (GWh)	**0.0**	**10.0**	75%	**10.0**	75%	**31**

Program-to-Date towards Target: Combination of verified (2011-12) and unverified (2013) results. To align with savings counted towards OEB targets, peak demand is represented by annual savings in 2014 and energy is represented by the cumulative savings from 2011-2014.

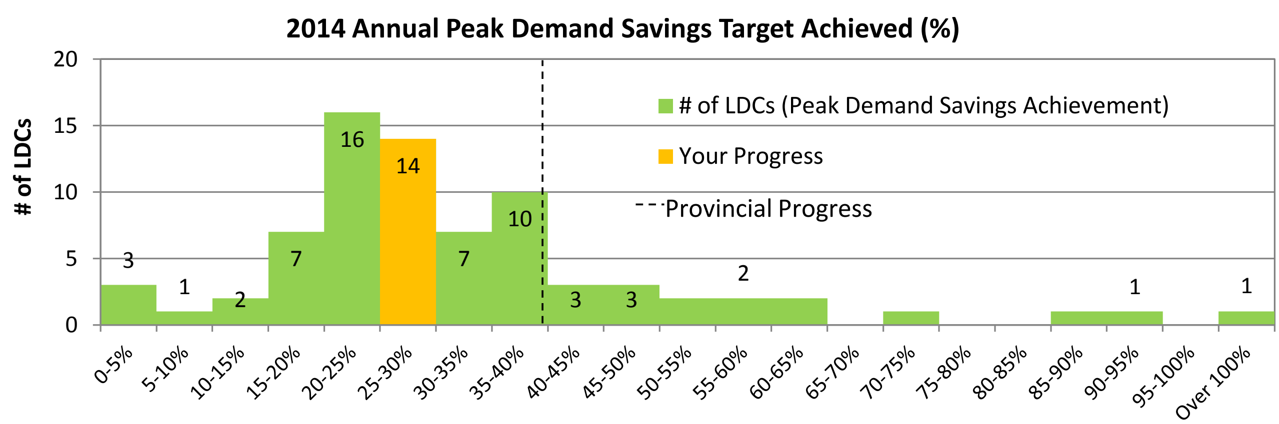
Scenario 1: Assumes that demand response resources have a persistence of 1 year. Official reporting policy for demand response resources.

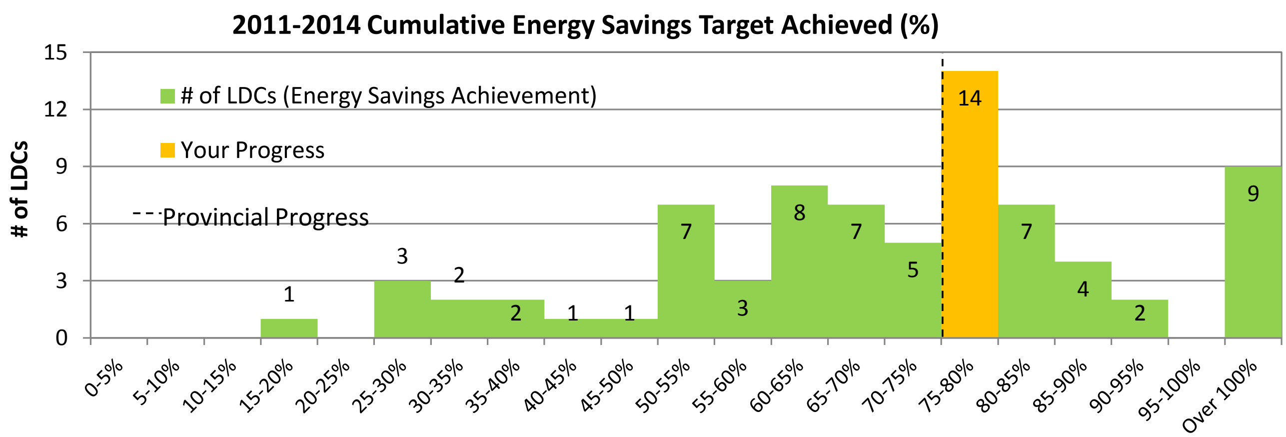
Scenario 2: Assumes that demand response resources remain in your territory until 2014. Used to better assess progress towards demand targets.

Rank: Sorts each LDC by % of peak demand or energy target achieved as of the current reporting period using Scenario 2.

Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)





Questions? Please check the "About this Report" Section on page 2, Table 5 on page 9 and "Reporting Methodology" on page 10.
More Questions? Please contact LDC.Support@powerauthority.on.ca

Message from the Vice President

I am pleased to present our Q3 2013 LDC report. We continue to achieve great success across all sectors. Provincially we have achieved 75% of the cumulative 6,000 GWh energy target and progress towards the 1,330 MW demand target increased from last quarter to 40%.

A few highlights of our current activities during this reporting period:

- In collaboration with the EDA Policy group and CDM Caucus, the final wave of change management to enable the 2015 extension is underway. Including changes to the Master Services Agreement, initiative contracts, participant agreements and vendor contracts. The changes include:
  - Enabling LDCs to request PAB increases, decreases and reallocations at their discretion
  - Clarification of PAB cost-effectiveness incentive
  - Extending all relevant terms to December 31, 2015
- Targeted workshops aimed at HVAC contractors focused on bringing attention to enhanced incentives and improved processes for replacing rooftop HVAC units (RTUs) within Retrofit has lead to an increase in RTU
- Business program continues to perform well and exceed expectations

Stay tuned for more information on these and more customer focused enhancements. We look forward to continuing to work together on evolving our conservation programs, and engaging channel partners across all sectors to further drive participation.

We encourage you to continue to contact us and tell us your ideas and success stories so we can share our experiences across the province.

Please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions regarding this report.

Congratulations on another successful quarter!

Sincerely,

Andrew Pride

About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not include Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts)
- Progress as of the end of Q3 2013 using unverified quarterly results for 2013 and final verified results for 2011-12
- Program activity data (i.e. projects completed, appliances picked up) completed on or before Sept 30, 2013 and received and entered into the OPA processing systems as per the dates specified in Table 5
- Updates to the previous quarter's participation as a result of further data received
- Information to assist the LDC in reconciling internal data sources with the data contained in this report. Table 5 contains:

  1. The date in which savings are considered to 'start';
  2. At what point the data becomes available to the OPA;
  3. The expected probability and magnitude of updates to the data as more information becomes available.
- iCON CRM Post Stage Retrofit Report data queried on October 17, 2013
  - Retrofit projects completed after December 31, 2011 will be tracked as part of the Business program only
- Preliminary results for peaksaverPLUS® representing customers that have signed a Participant Agreement and information has been successfully uploaded into the RDR settlement system
- peaksaver PLUS® reporting is split into two line items: Switch/Thermostat and IHD

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured to date through Tier 1 programs.
Table 1 presents:

- Net peak demand savings results from 2011 to Q3 2013 listed by implementation period, status (i.e. final or reported) and summarized by resource type (i.e. energy efficiency or demand response)
- Net annual peak demand savings that are expected to persist through to 2014 from program activity completed as of Q3 2013 using both Scenarios 1 and 2
- A comparison between reported, unverified results and final, verified results
- Energy efficiency resources reported with persistence according to the effective useful life of the technology

Figure 1 presents:

- Net peak demand savings results from 2011 to date using Scenario 1 for demand response resources (persistence of 1 year)

Please note: Demand response resources are only presented in the final quarter of each year and the current reporting quarter (i.e. Q4 2011, Q4 2012, and Q3 2013). Figures below and tables 3B and 4B present demand response in each quarter to display any changes that may have occurred quarter over quarter.

Table 1: Net Peak Demand Savings at the End-User Level (MW)

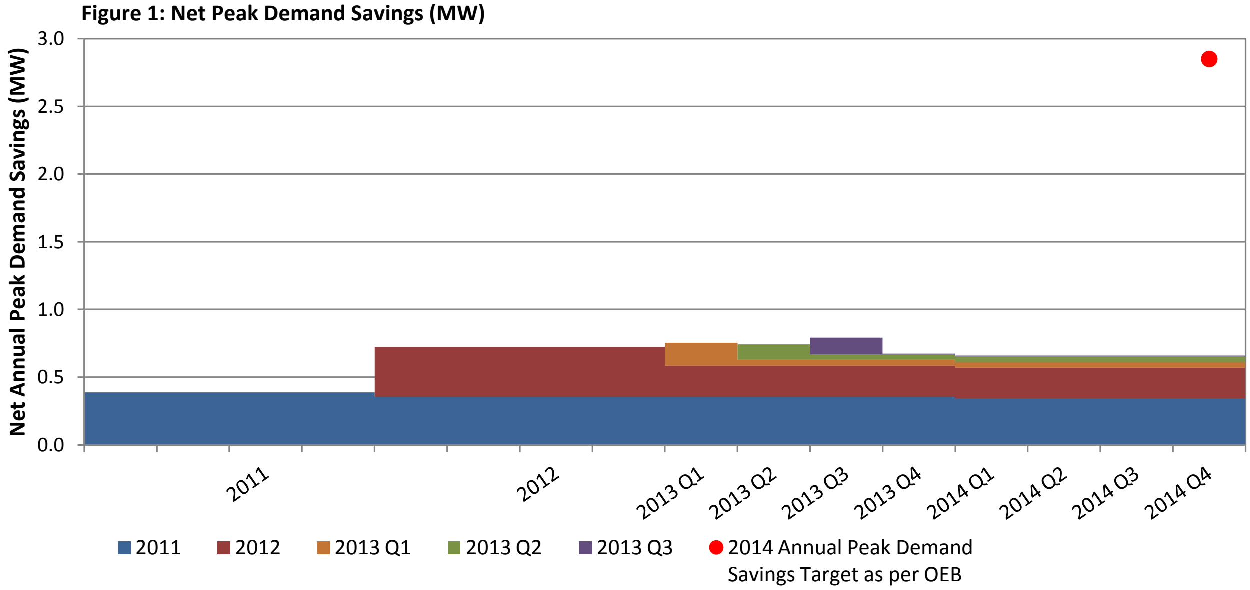
#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final*	0.39	0.36	0.36	0.34	0.34
2	2012 - Final*		0.37	0.23	0.23	0.23
3	2013 - Reported - Quarter 1			0.04	0.04	0.04
4	2013 - Reported - Quarter 2			0.04	0.04	0.04
5	2013 - Reported - Quarter 3			0.12	0.01	0.12
6	2014					
	Energy Efficiency	0.36	0.57	0.68	0.66	0.66
	Demand Response	0.03	0.14	0.12	0.00	0.12
	Net Annual Peak Demand Savings	0.39	0.72	0.79	0.66	0.78
	Unverified Net Annual Peak Demand Savings in 2014:				**0.7**	**0.8**
	2014 Annual Peak Demand Savings Target as per OEB:				**2.9**	**2.9**
	Unverified 2014 Peak Demand Savings Target Achieved (%):				**23%**	**27%**
	Incremental Reported (Unverified)	0.15	0.43	0.21		
	Incremental Final (Verified)	0.39	0.37	n/a		

* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)

Reported DR3 (Ex Ante) (MW)**	0.12
Contracted DR3 (MW)**	0.13

** Consistent with monthly DR3 reports at the end of each quarter

Figure 1: Net Peak Demand Savings (MW)



2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured to date through Tier 1 programs.

Table 2 presents net annual energy savings results from 2011 to date listed by implementation period, status (i.e. final or reported) and summarized by resource type. This table aligns with Scenario 1 and presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date. At the bottom of the table a comparison is made between reported results (unverified) and final results (verified) for 2011, 2012, and 2013 year-to-date.

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final*	1.56	1.56	1.56	1.52	6.21
2	2012 - Final*	-0.01	1.01	1.00	1.00	3.01
3	2013 - Reported - Quarter 1			0.16	0.16	0.33
4	2013 - Reported - Quarter 2			0.20	0.20	0.39
5	2013 - Reported - Quarter 3			0.04	0.04	0.08
6	2014					
	Energy Efficiency	1.56	2.56	2.96	2.92	10.01
	Demand Response	0.00	0.00	0.00	0.00	0.01
	Net Energy Savings	1.56	2.57	2.96	2.92	10.01
	Unverified Net Cumulative Energy Savings 2011-2014:					**10.0**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**13.3**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**75%**
	Incremental Reported (Unverified)	0.66	1.61	0.40		
	Incremental Final (Verified)	1.56	1.01	n/a		

Figure 2: Net Cumulative Energy Savings (GWh)

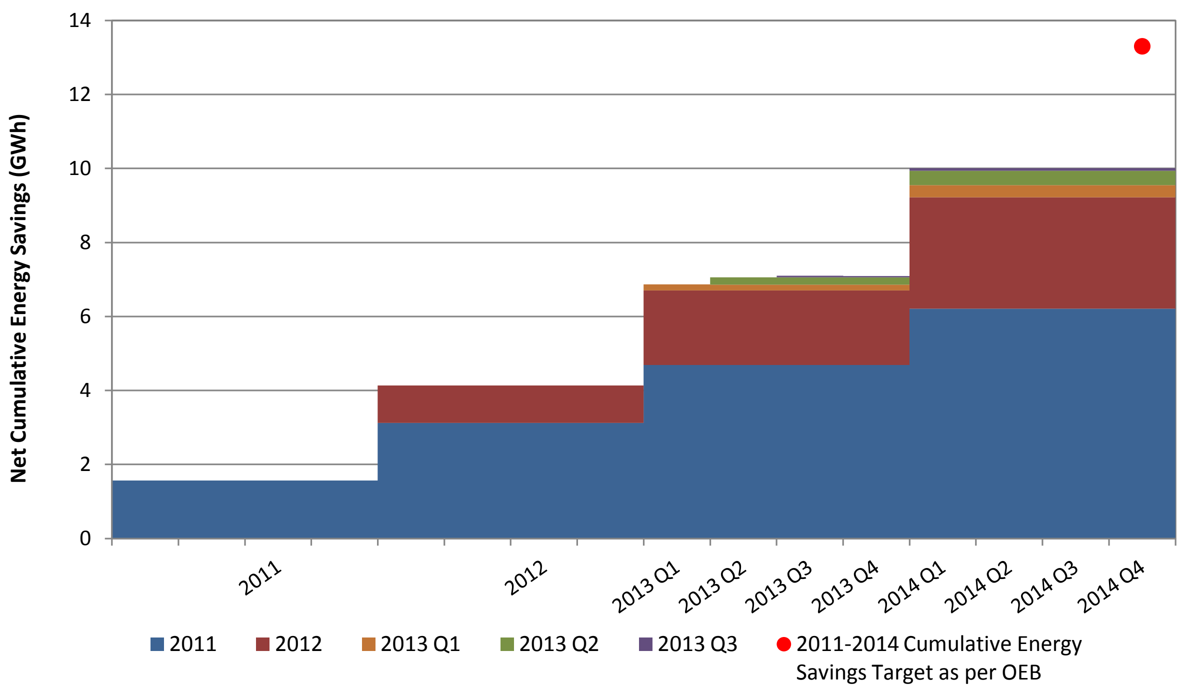


Table 3A: Haldimand County Hydro Inc. Initiative and Program Level Savings by Year (Scenario 1)

#	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 Unverified Progress to Target (excludes DR)	
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW) 2014	2011-2014 Net Cumulative Energy Savings 2014
Consumer Program																
1	Appliance Retirement	Appliances	270	154	78		16	9	5		115,815	61,427	31,549		29	710,640
2	Appliance Exchange	Appliances	22	36	4		2	5	0		2,618	9,228	304		6	37,447
3	HVAC Incentives	Equipment	323	251	160		103	57	35		186,931	98,468	58,309		195	1,159,747
4	Conservation Instant Coupon Booklet	Coupons	2,190	131	134		5	1	1		81,297	5,934	5,480		7	353,951
5	Bi-Annual Retailer Event	Coupons	4,041	4,503	904		7	6	2		124,723	113,664	29,198		15	898,279
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-		-	-
7	Residential Demand Response (switch/pstat)*	Devices	19	19	2		11	9	1		-	55	4		-	60
8	Residential Demand Response (IHD)	Devices	-	-	2		-		-		-		-		-	-
9	Residential New Construction	Homes	-	-	-		-	0	-		-	415	-		0	1,245
Consumer Program Total							**144**	**87**	**44**		**511,385**	**289,191**	**124,844**		**253**	**3,161,369**
Business Program																
10	Retrofit	Projects	6	20	7		70	109	33		435,855	503,091	182,689		212	3,618,070
11	Direct Install Lighting	Projects	44	50	10		61	40	12		156,830	149,154	56,938		99	1,148,199
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-		-	-
13	New Construction	Buildings	3	2	-		15	11	-		67,631	36,709	-		26	380,650
14	Energy Audit	Audits	-	-	-		-	-	-		-	-	-		-	-
15	Small Commercial Demand Response (switch/pstat)*	Devices	-	-	-		-	-	-		-	-	-		-	-
16	Small Commercial Demand Response (IHD)	Devices	-	-	-		-	-	-		-	-	-		-	-
17	Demand Response 3*	Facilities	-	-	-		-	-	-		-	-	-		-	-
Business Program Total							**147**	**160**	**44**		**660,315**	**688,954**	**239,626**		**336**	**5,146,919**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	-		-	-	-		-	-	-		-	-
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-		-	-
20	Energy Manager	Projects	-	-	-		-	-	-		-	-	-		-	-
21	Retrofit	Projects	-		-		-		-		-		-		-	-
22	Demand Response 3*	Facilities	1	2	2		21	129	117		1,237	3,114	2,617		-	6,968
Industrial Program Total							**21**	**129**	**117**		**1,237**	**3,114**	**2,617**		**-**	**6,968**
Home Assistance Program																
23	Home Assistance Program	Homes	-	33	110		-	3	2		-	30,560	30,369		5	152,417
Home Assistance Program Total							**-**	**3**	**2**		**-**	**30,560**	**30,369**		**5**	**152,417**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-		-	-
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Pre-2011 Programs completed in 2011																
25	Electricity Retrofit Incentive Program	Projects	3	-	-		4	-	-		24,629	-	-		4	98,518
26	High Performance New Construction	Projects	2	0	-		71	0	-		366,177	465	-		72	1,466,100
27	Toronto Comprehensive	Projects	-	-	-		-	-	-		-	-	-		-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-		-	-	-		-	-	-		-	-
29	LDC Custom Programs	Projects	-	-	-		-	-	-		-	-	-		-	-
Pre-2011 Programs completed in 2011 Total							**76**	**0**	**-**		**390,806**	**465**	**-**		**76**	**1,564,618**
Other																
30	Program Enabled Savings	Projects	-	-	-		-	-	-		-	-	-		-	-
31	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-		-	-
Other Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Adjustment to Previous Year's Verified Results								**(12)**				**(5,042)**			**(12)**	**(20,168)**
Energy Efficiency Total							**356**	**242**	**89**		**1,562,506**	**1,009,115**	**394,835**		**670**	**10,025,263**
Demand Response Total (Scenario 1)							**32**	**138**	**118**		**1,237**	**3,169**	**2,622**		**-**	**7,027**
OPA-Contracted LDC Portfolio Total							**387**	**368**	**206**		**1,563,743**	**1,007,242**	**397,457**		**659**	**10,012,122**
														Full OEB Target:	**2,850**	**13,300,000**
														% of Full OEB Target Achieved to Date (Scenario 1):	**23%**	**75%**

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 for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

Table 3B: Haldimand County Hydro Inc. Initiative and Program Level Savings by Quarter for current reporting 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)			
			Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Consumer Program														
1	Appliance Retirement	Appliances	31	21	25		2	1	1		12,768	8,594	10,187	
2	Appliance Exchange	Appliances	-	4	-		-	0	-		-	304	-	
3	HVAC Incentives	Equipment	80	60	20		19	12	4		33,278	18,844	6,187	
4	Conservation Instant Coupon Booklet	Coupons	77	46	11		1	0	0		3,380	1,706	394	
5	Bi-Annual Retailer Event	Coupons	19	879	6		0	2	0		535	28,473	191	
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-	
7	Residential Demand Response (switch/pstat)*	Devices	19	2	2		11	1	1		41	7	4	
8	Residential Demand Response (IHD)	Devices	-	2	-				-				-	
9	Residential New Construction	Homes	-	-	-		-	-	-		-	-	-	
Consumer Program Total							**32**	**17**	**6**		**50,002**	**57,928**	**16,963**	
Business Program														
10	Retrofit	Projects	3	4	-		8	25	-		49,198	133,491	-	
11	Direct Install Lighting	Projects	10	-	-		12	-	-		56,938	-	-	
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-	
13	New Construction	Buildings	-	-	-		-	-	-		-	-	-	
14	Energy Audit	Audits	-	-	-		-	-	-		-	-	-	
15	Small Commercial Demand Response (switch/pstat)*	Devices	4	-	-		2	-	-		8	-	-	
16	Small Commercial Demand Response (IHD)	Devices	-	-	-		-	-	-		-	-	-	
17	Demand Response 3*	Facilities	-	-	-		-	-	-		-	-	-	
Business Program Total							**22**	**25**	**-**		**106,143**	**133,491**	**-**	
Industrial Program														
18	Process & System Upgrades	Projects	-	-	-		-	-	-		-	-	-	
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-	
20	Energy Manager	Projects	-	-	-		-	-	-		-	-	-	
21	Retrofit	Projects												
22	Demand Response 3*	Facilities	2	2	2		113	71	117		6,607	1,602	2,617	
Industrial Program Total							**113**	**71**	**117**		**6,607**	**1,602**	**2,617**	
Home Assistance Program														
23	Home Assistance Program	Homes	14	3	93		1	1	1		7,236	3,883	19,250	
Home Assistance Program Total							**1**	**1**	**1**		**7,236**	**3,883**	**19,250**	
Aboriginal Program														
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-	
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**	
Pre-2011 Programs completed in 2011														
25	Electricity Retrofit Incentive Program	Projects	-	-	-		-	-	-		-	-	-	
26	High Performance New Construction	Projects	-	-	-		-	-	-		-	-	-	
27	Toronto Comprehensive	Projects	-	-	-		-	-	-		-	-	-	
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-		-	-	-		-	-	-	
29	LDC Custom Programs	Projects	-	-	-		-	-	-		-	-	-	
Pre-2011 Programs completed in 2011 Total							**-**	**-**	**-**		**-**	**-**	**-**	
Other														
30	Program Enabled Savings	Projects	-	-	-		-	-	-		-	-	-	
31	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-	
Other Total							**-**	**-**	**-**		**-**	**-**	**-**	
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**42**	**41**	**6**		**163,332**	**195,294**	**36,208**	
Demand Response Total (Scenario 1)							**125**	**72**	**118**		**6,656**	**1,609**	**2,622**	
OPA-Contracted LDC Portfolio Total							**168**	**113**	**124**		**169,988**	**196,903**	**38,830**	

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.

***Includes adjustments after Final Reports were issued**

**** Updates to the previous quarter's participation may occur as a result of further data received**

Table 4A: Province-Wide 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 Unverified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Unverified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	56,110	34,146	15,997		3,299	2,011	978		23,005,812	13,424,518	6,266,108		6,149	144,709,073
2	Appliance Exchange	Appliances	3,688	3,836	302		371	556	32		450,187	974,621	43,168		722	4,598,860
3	HVAC Incentives	Equipment	92,721	85,221	41,082		32,037	19,060	9,005		59,437,670	32,841,283	15,310,950		60,102	366,896,430
4	Conservation Instant Coupon Booklet	Coupons	567,678	30,891	31,584		1,344	230	225		21,211,537	1,398,202	1,291,133		1,800	91,623,019
5	Bi-Annual Retailer Event	Coupons	952,149	1,060,901	213,100		1,681	1,480	459		29,387,468	26,781,674	6,879,644		3,620	211,654,185
6	Retailer Co-op	Items	152	-	-		0	-	-		2,652	-	-		0	10,607
7	Residential Demand Response (switch/pstat)*	Devices	19,550	98,388	107,013		10,947	49,038	59,927		24,870	359,408	230,077		-	614,356
8	Residential Demand Response (IHD)	Devices	-	49,689	45,619		-		-		-		-		-	-
9	Residential New Construction	Homes	26	-	5		0	2	1		743	17,152	2,182		2	58,794
Consumer Program Total							**49,681**	**72,377**	**70,627**		**133,520,941**	**75,796,859**	**30,023,262**		**72,396**	**820,165,325**
Business Program																
10	Retrofit	Projects	2,819	5,605	3,875		24,467	61,147	30,118		136,002,258	314,922,468	197,951,323		114,136	1,876,550,105
11	Direct Install Lighting	Projects	20,741	18,494	10,815		23,724	15,284	11,102		61,076,701	57,345,798	47,871,034		42,283	486,814,937
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-		-	-
13	New Construction	Buildings	22	64	21		123	764	455		411,717	1,814,721	1,052,514		1,342	9,196,060
14	Energy Audit	Audits	196	280	95		-	1,450	492		-	7,049,351	2,391,744		1,941	25,931,542
15	Small Commercial Demand Response (switch/pstat)*	Devices	132	294	359		84	187	201		157	1,068	772		-	1,996
16	Small Commercial Demand Response (IHD)	Devices	-	-	82		-	-	-		-	-	-		-	-
17	Demand Response 3*	Facilities	145	151	171		16,218	19,389	24,055		633,421	281,823	536,899		-	1,452,143
Business Program Total							**64,617**	**98,221**	**66,422**		**198,124,253**	**381,415,230**	**249,804,286**		**159,702**	**2,399,946,783**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	1		-	-	270		-	-	825,000		270	1,650,000
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-		-	-
20	Energy Manager	Projects	-	39	35		-	1,086	679		-	7,372,108	6,958,584		1,765	36,033,492
21	Retrofit	Projects	433		-		4,615		-		28,866,840		-		4,613	115,462,282
22	Demand Response 3*	Facilities	124	185	281		52,484	74,056	149,404		3,080,737	1,784,712	3,354,125		-	8,219,574
Industrial Program Total							**57,098**	**75,141**	**150,354**		**31,947,577**	**9,156,820**	**11,137,709**		**6,648**	**161,365,347**
Home Assistance Program																
23	Home Assistance Program	Homes	46	5,033	11,239		2	566	1,631		39,283	5,442,232	9,455,190		2,200	35,394,211
Home Assistance Program Total							**2**	**566**	**1,631**		**39,283**	**5,442,232**	**9,455,190**		**2,200**	**35,394,211**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-		-	-
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	2,028	-	-		21,662	-	-		121,138,219	-	-		21,662	484,552,876
25	High Performance New Construction	Projects	179	69	9		5,098	3,251	1,806		26,185,591	11,901,944	12,769,879		10,155	165,987,955
26	Toronto Comprehensive	Projects	577	-	-		15,805	-	-		86,964,886	-	-		15,805	347,859,545
27	Multifamily Energy Efficiency Rebates	Projects	110	-	-		1,981	-	-		7,595,683	-	-		1,981	30,382,733
28	LDC Custom Programs	Projects	8	-	-		399	-	-		1,367,170	-	-		399	5,468,679
Pre-2011 Programs completed in 2011 Total							**44,945**	**3,251**	**1,806**		**243,251,550**	**11,901,944**	**12,769,879**		**50,001**	**1,034,251,788**
Other																
29	Program Enabled Savings	Projects	-	-	-		-	2,304	-		-	1,188,362	-		2,304	3,565,086
30	Time-of-Use Savings	Homes	-	-	-		-	-			-	-	-		-	-
Other Total							**-**	**2,304**	**-**		**-**	**1,188,362**	**-**		**2,304**	**3,565,086**
Adjustment to Previous Year's Verified Results								**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total							**136,610**	**109,191**	**57,253**		**603,144,419**	**482,474,435**	**309,068,454**		**293,251**	**4,444,400,472**
Demand Response Total (Scenario 1)							**79,733**	**142,670**	**233,587**		**3,739,185**	**2,427,011**	**4,121,872**		**-**	**10,288,069**
OPA-Contracted LDC Portfolio Total							**216,343**	**253,267**	**290,840**		**606,883,604**	**503,590,526**	**313,190,326**		**294,407**	**4,528,607,138**

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.

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 for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

	kW	kWh
Full OEB Target:	**1,330,000**	**6,000,000,000**
% of Full OEB Target Achieved to Date (Scenario 1):	**22%**	**75%**

Table 4B: Province-Wide Initiative and Program Level Savings by Quarter for Current Reporting 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)			
			Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Consumer Program														
1	Appliance Retirement	Appliances	4,372	5,381	6,244		262	331	385		1,726,524	2,098,963	2,440,621	
2	Appliance Exchange	Appliances	10	130	162		1	14	18		1,138	17,249	24,780	
3	HVAC Incentives	Equipment	13,780	18,689	8,613		3,406	3,865	1,734		6,143,456	6,366,357	2,801,138	
4	Conservation Instant Coupon Booklet	Coupons	18,180	10,830	2,574		195	24	7		796,461	401,881	92,790	
5	Bi-Annual Retailer Event	Coupons	4,425	207,168	1,507		7	445	7		125,949	6,708,799	44,896	
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-	
7	Residential Demand Response (switch/pstat)*	Devices	71,642	96,264	107,013		40,120	50,316	59,927		153,447	363,663	230,077	
8	Residential Demand Response (IHD)	Devices	15,153	25,864	4,602				-				-	
9	Residential New Construction	Homes	3	1	1		0	1	0		756	1,272	154	
Consumer Program Total							**43,990**	**54,995**	**62,077**		**8,947,731**	**15,958,184**	**5,634,456**	
Business Program														
10	Retrofit	Projects	1,321	1,509	1,045		11,208	11,615	7,295		70,694,979	66,323,123	60,933,222	
11	Direct Install Lighting	Projects	3,877	4,676	2,262		3,986	4,853	2,264		15,540,497	22,208,242	10,122,295	
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-	
13	New Construction	Buildings	12	7	2		233	97	125		735,556	220,560	96,399	
14	Energy Audit	Audits	51	38	6		264	197	31		1,283,989	956,698	151,058	
15	Small Commercial Demand Response (switch/pstat)*	Devices	241	144	359		135	92	201		463	523	772	
16	Small Commercial Demand Response (IHD)	Devices	29	47	6		-	-	-		-	-	-	
17	Demand Response 3*	Facilities	153	170	171		20,082	27,275	24,055		786,518	608,767	536,899	
Business Program Total							**35,907**	**44,129**	**33,970**		**89,042,001**	**90,317,913**	**71,840,643**	
Industrial Program														
18	Process & System Upgrades	Projects	1	-	-		270	-	-		825,000	-	-	
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-	
20	Energy Manager	Projects	26	8	1		429	250	-		3,647,428	3,311,156	-	
21	Retrofit	Projects			-				-				-	
22	Demand Response 3*	Facilities	210	270	281		78,121	106,583	149,404		4,585,608	2,392,785	3,354,125	
Industrial Program Total							**78,820**	**106,833**	**149,404**		**9,058,036**	**5,703,941**	**3,354,125**	
Home Assistance Program														
23	Home Assistance Program	Homes	3,408	5,092	2,739		795	750	86		3,840,100	4,015,556	1,599,534	
Home Assistance Program Total							**795**	**750**	**86**		**3,840,100**	**4,015,556**	**1,599,534**	
Aboriginal Program														
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-	
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**	
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	-	-	-		-	-	-		-	-	-	
25	High Performance New Construction	Projects	4	-	5		731	-	1,075		5,563,680	-	7,206,199	
26	Toronto Comprehensive	Projects	-	-	-		-	-	-		-	-	-	
27	Multifamily Energy Efficiency Rebates	Projects	-	-	-		-	-	-		-	-	-	
28	LDC Custom Programs	Projects	-	-	-		-	-	-		-	-	-	
Pre-2011 Programs completed in 2011 Total							**731**	**-**	**1,075**		**5,563,680**	**-**	**7,206,199**	
Other														
29	Program Enabled Savings	Projects	-	-	-		-	-	-		-	-	-	
30	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-	
Other Total							**-**	**-**	**-**		**-**	**-**	**-**	
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**21,786**	**22,442**	**13,025**		**110,925,512**	**112,629,856**	**85,513,085**	
Demand Response Total (Scenario 1)							**138,458**	**184,265**	**233,587**		**5,526,035**	**3,365,737**	**4,121,872**	
OPA-Contracted LDC Portfolio Total							**160,244**	**206,707**	**246,612**		**116,451,548**	**115,995,594**	**89,634,957**	

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.

***Includes adjustments after Final Reports were issued**

**** Updates to the previous quarter's participation may occur as a result of additional data received**

Table 5: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Data included in the Q3 2013 report includes all program activity completed (as per the savings 'start' date) on or before September 30th, 2013.

Initiative	Savings 'start' Date	Data Available	Additional Data Likely
Consumer Program			
Appliance Retirement	Pick-up date	When database is queried. Typically up-to-date.	Moderate
Appliance Exchange	Exchange event date	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
HVAC Incentives	Installation date1	Rebate Status = Approved, Cheque Issued and Cheque Cashed; Typically 1 - 4 months delay.	High
Conservation Instant Coupon Booklet	Coupon redemption year	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
Bi-Annual Retailer Event	Year and quarter of the event		High
Retailer co-op activities	Will vary by specific project	Will vary by specific project	Low
Residential Demand Response	Device installation date	Data successfully uploaded into RDR settlement system as of Sept 30th, 2013	High
Residential New Construction	Project completion	Preliminary Billing Report submitted to OPA	Low
Business (Commercial & Institutional) Program			
Retrofit	Actual project completion date	In the "Post Project Submission" Stage (excluding "Payment Denied by LDC") within iCON CRM as of October 17, 2013	Low
Direct Installed Lighting	Retrofit date	Work-order: invoiced, approved and paid to LDC. Typically 1.5 - 2 months delay. Any projects that are flagged as duplicates will not appear in reports until duplicates have been resolved.	High
Building Commissioning	Hand off date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
New Construction	Actual project completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Energy Audit	Audit completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Small Commercial Demand Response	Device installation date	Data successfully uploaded into RDR settlement system	Moderate
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator	Low
Industrial Program			
Process & System Upgrades	In-service date	Preliminary Billing Report submitted to OPA and reviewed	Low
Monitoring & Targeting	Project completion date	Preliminary Billing Report submitted to OPA and reviewed	Low
Energy Manager (EEM or REM)	Project completion date	Completed, non-incented projects submitted quarterly by Energy Manager.	High
Retrofit	All Retrofit projects are now reported under the Business Program		
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator.	Low
Home Assistance Program			
Home Assistance Program	Project completion date	Preliminary Billing Report submitted to OPA and reviewed	High
Pre-2011 Projects Completed in 2011			
High Performance New Construction	Project completion date	Reviewed and processed from delivery agent, quarterly	Moderate

1: Monthly reports split savings into months using the approval date

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). Annual savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011.

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.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

Effective Useful Life: detemines the persistence of savings for a given technology or initiative. Factors that may effect the useful life of a technology are typical use and operating hours, upcoming code changes, etc. Demand response resources are assumed to have a persistence of 1 year.

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). All savings presented in this report are at the end-user level.

Final or Verified Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

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). Incremental savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011 (i.e. Incremental = Annual for demand response only).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported or Unverified Savings: savings achieved that are based on reported activity and forecasted or best available savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Reporting Methodology (Quarterly, Unverified results):

There are several resources on reporting that are available to LDCs:

- Reporting Policy & FAQ Document found on the iCON Portal in the "Other Program Materials" under "Reporting Tools"
- LDC Consumer Program Tracking Tool found on the iCON Portal in "Other Program Materials" under "Reporting Tools"
- Webinars (available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php)
  - Understanding your Q4 2011 Report (April 11, 2012)
  - Tools from the Reporting WG (April 25, 2012)
  - A Deeper Look at: peaksaverPLUS® (May 23, 2012)
  - A Deeper Look at: Demand Response 3 (June 6, 2012)
  - Revisiting Reporting (June 20, 2012)
  - Quarterly CDM Status Report update (October 24, 2012) http://powerauthority.webex.com; password: DCx2012