Coopérative Hydro Embrun Inc.

October 10, 2013
Ontario Energy Board P.O.
Box 2319 27th Floor
2300 Yonge Street Toronto,
Ontario M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary
Regarding: EB-2013-0122-2014 Cost of Service Application

Dear Ms. Walli,

Cooperative Hydro Embrun Inc. is pleased to submit to the Ontario Energy Board its Responses to VECC and Board Staff' s interrogatories. This application is being filed pursuant to the Board's e-Filing Services.

We would be pleased to provide any further information or details that you may require relative to this application.

Yours truly,

Benoit Lamarche, General Manager
Cooperative Hydro Embrun
703 Notre Dame Rue Russell, ON
(613) 443-5110

Response to Board Staff and VECC Interrogatories
2014 Electricity Distribution Cost of Service Application
Cooperative Hydro Embrun Inc. (“CHEI”) EB-2013-0122
October 10, 2013

Exhibit 1 – General

1-Staff-1

Updated Revenue Requirement Work Form

Upon completing responses to all interrogatories from Staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or any explanatory note.

Response: An updated version of the Revenue Requirement Work Form is being filed in conjunction with these responses.

1-Staff-2

Updated Appendix 2-W – Bill Impacts

Upon completing responses to all interrogatories from Staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption/demand levels (i.e. 800 kWh for Residential, 2,000 kWh for General Service Less Than 50 kW).

Response: An updated version of the Bill Impacts is being filed in conjunction with these responses and also presented at Appendix B-C of these responses.

1-Staff-3

Ref: E1.T1.S6 – Cooperative Membership

On page 13 of Exhibit 1, CHEI indicates that each customer is a member and owner of the business (I.e. CHEI) with an equal say as every other member of the cooperative. CHEI also indicates that the coop members determine objective, financing, operating policies and method of sharing benefits.

a) Under what circumstance can one member own multiple shares in CHEI?

b) How does CHEI manage disputes and/or differing opinions within its membership?
c) Please describe in detail what types of decision making are CHEI's members actively participating in?
d) Please provide a summary of the skills and experience that coop members have in determining CHEI's objectives, financing, operating policies, etc.
e) How frequent are meetings with CHEI's members? Is a voting system used in decision making?

Response to a) b) c) d) e):

The cooperative is overseen by a Board of Director which is elected by the Cooperative members on a yearly basis. The three Board members are elected to act as representatives of the members of the Cooperative. Their role involves establishing corporate management related policies and to make decisions on major company issues. Such issues include; capital budget and operational budget, patronage dividend and compensation. Members have an opportunity to voice their questions, concerns or comments at an annual meeting where issues are reviewed, motions are moved and second by the members. Members generally only own one share of the Cooperative however it is possible for a member to own multiple shares if the member has an account in 2 or more different classes. A member can only own one share per class.

Members of the Cooperative actively participate in the following decision making aspect of the cooperative.

- Elect Board Members
- Review and Approve new development and major capital investment in the current year.
- Review and Approve the overall utility statistics
- Review and Approve the social responsibility report
- Review and Approve the cooperative's financial statements
- Review and Approve the patronage return
- Review and Approve auditors for the next fiscal year

The Board of Directors meet with the Manager of the utility on a monthly basis to review all aspect of the utility. Depending the level of activity happening at the time, the Board may meet on a more frequent basis (i.e. Cost of Service, new subdivision…) The Board of Director have expert knowledge of the operational, financial, customer engagement and day to day operation of the utility. All 3 Board members and the Manager each patrol a quarter of the service area on a weekly basis to perform a visual inspection of the distribution system.

CHEI 's Board of Director is comprised of 3 Board Members which have a combined 55 years of experience in overseeing the utility. The Board of Director is comprised of a lawyer and two directors with extensive financial background.

The Board is actively involved in all aspect of the utility including cost of service application, capital and operational budget and also approves all significant expenditures including the reviews and renewal of all external services or consultants (i.e. Sproule Powerline, BDO, Stantec and Tandem Energy Services Inc.).

1-Staff-4

Ref: E1.T1.S14 – Conditions of Service

On page 18 of Exhibit 1, CHEI has indicated that it is in the process of updating its conditions of service.

a) What is the status of this update?

Response: The updates to the Conditions of Service is done in collaboration with Hydro Hawkesbury and Hydro 2000. The completed draft Conditions of Service is pending a group review once IRs for both Cooperative Hydro Embrun and Hydro Hawkesbury have been completed.

a) Staff notes that Conditions of Service should not contain any rates or charges. Please confirm that this update will not have any rate impacts on CHEI's customers.

Response: Confirmed

b) Are there any additional anticipated costs for updating CHEI's conditions of service?

Response: No additional costs are expected for the update to the Conditions of Service. The costs are included in the yearly service contract with Tandem Energy Services Inc.

1-Staff-5

Ref: E1.T2.S3 – OM&A Costs

On page 24 of Exhibit 1, CHEI indicates that OM&A cost expenditures for the 2014 test year are the result of a planning and work prioritization process.

a) Please explain what type of criteria or strategy is used to determine which solutions are the most cost effective for CHEI and its customers.

Response:

CHEI and its Board of Director are very cost conscientious. Wherever possible, CHEI will find the most reliable and cost effective solution available. The Manager will review all OM&A expenses on a regular basis and determine if a more cost effective option is available. CHEI's approach to cost management is to that the utility will operate within the confines of its approved revenue requirement as much as possible.

b) Who is involved in this planning and work prioritization process?

Response: The Manager and the Board of Directors.

1-Staff-6

Ref: E1.T3.S1 – Audited Financial Statements

On page 12 of CHEI's 2012 Audited Financial Statements, under Note 6, $334,135 for smart meters seems to be included under regulatory assets.

a) Please confirm that CHEI had its smart meters reviewed and approved in a stand-alone smart meter application in EB-2012-0094.

Response: Confirmed

b) The Board's decision was issued on August 23, 2012. CHEI should have made the accounting changes to add in the smart meters before December 31, 2012. However, between Notes 6 and 7, it does not seem that smart meters have been transferred from regulatory assets to rate base as of December 31, 2012. Please confirm that CHEI has done so. If it has not, please explain.

Response: CHEI has reviewed the decision and has not been able to find where the Board directed the utility to transfer its balances to rate base. CHEI and its auditors BDO confirm that this accounting change was not done however, the accounting change can and will be done at the end of 2013.

1.0 –VECC-1

Reference: Exhibit 1, Tab 1 (E1.T1.S6) / Exhibit 4, Tab 9

a) Please provide the total number of cooperative memberships in 2012 and the total number of accounts eligible for membership in 2012.

Response:

	Members	Account Eligible
Res	1172	1727
GS<50	77	91
GS>50	8	16
USL	0	4
StreetLights	0	0

b) Please explain how non-members are recruited or informed of their right to become a member.

Response: New customer are informed when they contact the utility to request a service connection. Customers are also informed through various media such as Bill inserts and “Semaine de la Cooperative” which occurs in October of every year. The published Annual Report also provides information on membership costs.

c) For membership disbursement paid in 2012, please provide the lowest and highest membership dividend and the average residential account dividend.

Response: Dividends are not based on consumption therefore the amount paid is per customer is consistent as shown in table below.

	Members	Account Eligible
Res	1172	$40/customer
GS<50	77	$55/ customer
GS>50	8	$600/customer

d) If any town or township is a member please provide the disbursement made to that entity in 2012.

Response Township of Russell has an account in each general service class: GS<50: $55 and GS>50 $600

Exhibit 2 – Rate Base

2-Staff-7

Ref: E2.T2.S4 – 2013 Capital Budget

On page 7 of Exhibit 2, CHEI has indicated that the projected average balance in 2013 of $2.1 million is $186,000 or 10% greater than 2012. CHEI noted that the increase is primarily due to significant monies budgeted for overhead and underground conductors and devices ($111,000), and poles and transformer ($84,000), as well as $62,000 budgeted for upgrades to CHEI's distribution station equipment in advance of the subdivision in 2014-2015.

a) Please reconcile the amounts mentioned above for the overhead and underground conductors and devices, poles and transformers and upgrades to the distribution station equipment with the amounts stated in the 2013 Capital Budget table provided on page 23 of Volume 2.

Response: Please see table below

2013 Capital budget

GL ACT #	2013 CAPITAL PROJECTS DESCRIPTION	AMOUNT	
1820	GROUNDY STUDY SUBSTATION	$10 000.00	
	ADD NEW SWITCHING CABINET 4TH FEEDER	$52 400.00	
	SUB TOTAL	$62 400.00	$62,000
	Subtotal		$62,000
1830	REPLACE POLES, FIXTURES AS PER ASSET MANAGEMENT PLAN		
	NOTRE-DAME STREET REPLACE 2 POLES	$10 400.00	
	BOURDEAU CRESCENT REPLACE 1 POLE	$4 200.00	
	ST-JACQUES ROAD REPLACE 2 POLES	$ 3 650.00	
	BRISSON STREET REPLACE ONE POLE	$ 3 000.00	
	NOTRE-DAME STREET (DAMAGE POLE)	$ 7 800.00	
	SUB TOTAL	$29 050.00	$29,000
1830	STE-THÉRÈSE STREET 4T FEEDER	$54 800.00	$54,000
	Subtotal		$84,000
1835	STE-THÉRÈSE STREET 4T FEEDER	$58 750.00	$59,000
1845	UG CABLE SUBSTATION TO STE-THÉRÈSE	$52 400.00	$52,000
	Subtotal		$111,000
1850	TRANSFORMERS FOR REPLACING AND NEW SERVICES	$12 000.00	
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$5 000.00	
1915	CELL PHONE & EQUIPMENT	$1,500.00	
1920	COMPUTER EQUIPMENT AND HARDWARE BATTERY BACK-UP	$1 500.00	
1925	HARRIS SOFTWARE MOE STANDARD BILL PRINT	$25 000.00	
1925	ANTIVIRUS PROTECTION	$1 500.00	
1995	CONTRIBUTED CAPITAL	-$(8000.00)	
	TOTAL	$295 900.00	

2-Staff-8

Ref: E2.T2.S2 Appendix 2-A Capital Projects Table – Pole Replacement CHEI has indicated various amounts from 2008 to 2014 for pole replacements (e.g. $18,322.50 for 2008, $43,906.50 for 2009, $62,255.50 for 2010, etc.).

a) Please provide a detailed description of what factors determine the cost of pole replacements.

Response: The pole replacement depends largely on the type of attachments to the pole. A pole replacement can range from $1,200 to $8,000. CHEI has attached invoices of both a lower cost pole replacement and higher cost pole replacement.

b) What is the average cost per pole replacement?

Response: as mentioned above, the cost can vary depending on the type of pole and attachment.

SPROULE POWERLINE CONSTRUCTION LTD.
1420 County Road 10, West
Vankleek Hill, Ontario K0B 1R0
Tel: (613) 678-2266
Fax: (613) 678-3081

SPL SPROULE

Invoice #	30470
Date	Apr 30, 2013
Page	1

BILL TO:

Cooperative Hydro Embrun Inc.
821, rue Notre-Dame
Suite #200
Embrun, ON K0A 1W1

Business No.: 10497 3698 RT0001

Quantity	Description	Tax	Unit Price	Amount
1	Supply and Install 1-35' Class 5 Wood Pole at Water Tower Gate, as per our Proposal #2013-17-GM	H	1,200.00	1,200.00
	Date of Completion: April 10th			
	H - HST @ 13%			
	HST			156.00

183000
Be

Workmanship Performed to E.S.A. Standards	**Total Amount**	1,356.00

SPROULE POWERLINE CONSTRUCTION LTD.
1420 County Road 10, West
Vankleek Hill, Ontario K0B 1R0
Tel: (613) 678-2266
Fax: (613) 678-3081

BILL TO:

Cooperative Hydro Embrun Inc.
821, rue Notre-Dame
Suite #200
Embrun, ON K0A 1W1

Invoice #	30486
Date	May 14, 2013
Page	1

Business No.: 10497 3698 RT0001

Quantity	Description	Tax	Unit Price	Amount
1	Pole Replacement at Intersection of Notre-Dame and Lapalme, as per our Proposal #2013-26-GM -Supply & Install 50' Cl 3 Pole -Supply & Install 2 Span Guys -Relocate existing Transformer to new pole -Supply & Install 100 Amp Cutout, 6kV Lightning Arrester & Mounting Bracket -Relocate existing Primary & Secondary OH Conductors to new pole -Relocate existing Streetlight to new pole -Demolish & remove Concrete encasement of existing pole Old Transformer: S/N 261326; 75 kVA; 1972 New Transformer: Maloney; S/N 900369-5; 75 kVA; 02/2012 H - HST @ 13%	H	7,800.00	7,800.00
	HST			1,014.00

Workmanship Performed to E.S.A. Standards	**Total Amount**	8,814.00

2-Staff-9

Ref: E2.T2.S2 Appendix 2-A Capital Projects Table – 4th Feeder

CHEI has indicated that the 4th Feeder for Ste-Therese in 2013 is $58,750 and the 4th Feeder for Cloutier Street in 2014 is $19,375.

a) Please explain what factors cause the costs between the 4th Feeder for these streets to differ?

Response: The reason Ste-Therese Street's costs were nearly double that of Cloutier Street is simply due to the fact that Ste-Therese is a longer street. Ste-Therese is 0.6 km while Cloutier Street is only 0.2km. The Ste-Therese project involved replacing 6 poles vs 3 poles on Cloutier.

b) Does CHEI anticipate installing a 5th or 6th Feeder in the near future?

Response: no, the utility cannot add any more feeders. The next step would be to add a substation which may occur in 2018.

2-Staff-10

Ref: E2.T2.S3 Table 10 Summary of Project Need – Project Classification and Categorization

Please provide a reconciliation of the non-discretionary costs (development of $418,845 and sustainment/maintenance of $40,750) with the capital projects costs associated with the new subdivision.

Response: All cost related to the new subdivision are considered non-discretionary. The only cost that is considered discretionary relates to the 15K for Harris's Customer Connect.

GL ACT #	2014 CAPITAL PROJECTS DESCRIPTION	AMOUNT	
1830	REPLACE POLES, FIXTURES AS PER ASSET MANAGEMENT PLAN		
	ST-JACQUES ROAD 3 SPAN DEAD END POLE	$ 9 850.00	
	1179 ST-JACQUES REPLACE ONE POLE	$ 5 500.00	
	65 FORGET REPLACE ONE POLE	$ 5 400.00	
	SUB TOTAL	**$ 20 750.00 (9)**	Sustainment and Maintenance
1830	CLOUTIER STREET 4TH FEEDER	**$ 39 470.00 (1)**	Non-discretionary
1835	CLOUTIER STREET 4TH FEEDER	**$19 375.00 (2)**	Non-discretionary

1845	PARC RICHELIEU 4TH FEEDER	$ 98 000.00	
	PATENAUDE SUBDIVSION (100 UNITS)	$ 120 000.00	
	BRISSON PROJECT OLIGO (50 UNITS)	$ 60 000.00	
	DOMAINE VERSAILLE PHASE (50 UNITS)	$ 60 000.00	
	MAURICE LEMIEUX NEW YORK CENTRAL PROJECT (50 UNITS)	$ 60 000.00	
	SUB TOTAL	**$ 398 000.00 (3)**	Non-discretionary
1850	TRANSFORMERS FOR THE PROPOSED SUBDIVISION AND LDC NEED	$ 87 500.00 (4)	Non-discretionary
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$ 4 000.00 (5)	Non-discretionary
1860	SMART METERS (300)	$30 500.00 (6)	Non-discretionary
1925	HARRIS VERSION 6.4 UPGRADE	$ 20 000.00 (10)	Sustainment and Maintenance
	HARRIS - CUSTOMER CONNECT	$ 15 000.00 (8)	Discretionary
	SUB TOTAL	**$ 35 000.00**	
1995	CONTRIBUTED CAPTAL	$-(160 000.00) (7)	Non-discretionary
	TOTAL	$ 474 595.00	

Non-Discretionary	Discretionary	Maintenance
(1) 39,470	(8)15,000	(9) 20,750
(2) 19,375		(10) 20,000
(3) 398,000		
(4) 87,500		
(5) 4,000		
(6) 30,500		
(7) (160,000)		
418,845	15,000	40,750

2-Staff-11

Ref: E2.T2.S4 Historical and Projected Capital Plans – New Subdivision CHEI has forecasted $398,000 for the new subdivision in what appears to be underground cable or underground conductors for 2014.

a) Please provide a detailed breakdown of $398,000 between underground cables and/or underground conductors. If there are other components besides underground cables and/or underground conductors included in the $398,000, please list them.

Response: The costs include only cables and installation. There are no other costs included in this account.

On page 33 of Exhibit 2, CHEI has noted that “after discussion with the municipality there will be four new projects in CHEI’s service area”. CHEI indicated that as an objective, “to respond to entrepreneur’s request if in fact request for new subdivision arise and sufficient transformers.”

b) Please provide a description of what these four projects are and also include the estimated number of residential, small businesses, street lights, and unmetered scattered load customers.

Response: No detailed description of the project other than preliminary plans and counts from the developer and municipality is known to CHEI. As explained at E3.T1.S4, the utility has been advised to expect and plan for 200 new connections by the end of 2014.

c) Who is CHEI referring to as the entrepreneur?

Response: The developer

d) What are the estimated capital contributions that will be required from the entrepreneur for the new subdivision?

Response: As indicated in the 2014 project table, the estimated capital contribution is in the amount of $160,000 or $640 per connection.

2-Staff-12

Ref: E2.T2.S4 Historical and Projected Capital Plans – Harris Software MOE Standard Bill Print

On page 29 of Exhibit 2, CHEI has indicated capital costs of $25,000 for 2013 related to the Harris Software MOE (Ministry of Energy) standard bill print to follow the direction of the Ministry of Energy.

a) Please provide a copy of the directive that was given to CHEI by the Ministry of Energy.

Response: Although CHEI has not been able to find direction from the Ministry of Energy, the utility has attached a copy of the letter it received from its bill presentment provider Northstar.

See Appendix A for the letter.

c) As of what date did CHEI start using the standard bills for time-of-use rates?

Response: January 2011

d) Please confirm if the $25,000 is a one-time cost or an on-going cost.

Response: The $25,000 is a one time capital cost.

2-Staff-13

Ref: E2.T2.S4 Historical and Projected Capital Plans – Harris Version 6.4

On page 35 of Exhibit 2, CHEI has forecasted $20,000 in 2014 for a Harris version 6.4 upgrade. CHEI has indicated that the objectives of this upgrade is to provide tools to management to perform regular tasks as well as protect actual hardware as required by the service provider.

a) Please identify whether there are any associated training costs for staff for the upgrade. If so, has CHEI requested these costs in OM&A or are they included in this amount?

Response: Training costs are included in the upgrade costs.

2-Staff-14

Ref: E2.T2.S4 Historical and Projected Capital Plans – Harris Customer Connect On page 35 of Exhibit 2, CHEI has forecasted $15,000 in 2014 for Harris Customer Connect. CHEI has indicated that it will provide a "Customer Connect" tool to its customers to help and promote energy conservation.

a) Please confirm if this a one-time cost or an ongoing cost.

Response: CHEI is of the view that it's only a one time capital cost as long as the Ministry of Energy doesn't propose any changes in the near future.

b) Please describe what energy conservation tools the "Customer Connect" will provide to CHEI's customers.

Response:

Benefits for Customers: CustomerConnect represents a new level of interaction with utilities. The tool will assist customers in understanding its web-based interface quickly and easily, and be able to access consumption data on a near real-time basis. CustomerConnect helps businesses and homeowners measure, monitor and manage usage patterns, access targeted educational materials and address account questions without ever needing to contact your utility's customer service representatives

Benefits for LDC ,CustomerConnect offers sophisticated functionality that helps municipalities and co-operative entities meet government regulatory requirements, demonstrate the value of their smart infrastructure investments to customers, augment public participation in key conservation programs and facilitate business process improvements to save money in the short- and long-term.

2-Staff-15

Ref: E2.T2.S4 Historical and Projected Capital Plans – Smart Meter Toll Deployment

On page 19 of Exhibit 2, CHEI has indicated $4,205 for Smart Meter Toll Deployment.

a) Please provide a description of what this is.

Response: There was a typographical error in the document. The description should have said "Tool" instead of "Toll". CHEI notes that these capital costs are related to seals and meter rings and were approved in the Smart Meter Application.

b) Does CHEI anticipate this amount being a one-time cost or ongoing?

Response: As mentioned above, these capital expenses were approved as part of the smart meter application.

2-Staff-16

Ref: E2.T2.S4 Historical and Projected Capital Plans – New Services

On page 22 of Volume 2, CHEI has indicated the total cost in 2012 for installation of overhead or underground facilities for new customers is $4,389.50. Staff is unable to reconcile this amount with the 2012 Capital Expenditures table on page 19 nor Appendix 2-A Capital Projects Table A. Please reconcile the difference and explain the discrepancy. Response: 5074 instead of 4389.50

Response: The description at page 22 should have read $5,074 instead of $4,389.

2-Staff-17

Ref: E2.T2.S4 Historical and Projected Capital Plans – Installed 4th Feeder Switch

On page 24 of Exhibit 2, CHEI indicates that the total estimated cost in 2013 of installing a new 4th Feeder switch to prepare for future grown in 2015 is $52,400.

a) Please provide the status of this installed 4th feeder switch. Is this feeder switch in service?

Response: The 4th feeder switch goes along Ste-Therese Street and branches north onto Cloutier. The Ste-Therese Street portion has been fully completed while Cloutier Street is scheduled for early 2014. CHEI notes that Cloutier Street can only be done once Ste-Therese has been completed.

b) Is this 4th feeder related to Ste-Therese? If so, please reconcile the $52,400 with the $58,750 inputted into Appendix 2-A for the 4th Feeder for Ste-Therese in 2013.

Response: The $58,750 relates to account 1835 conductors and devices and the $54,800 relates to account 1830 and involves the necessary replacement of poles to accommodate the new feeder switch.

c) Is this 4th feeder related to Cloutier Street? If so please reconcile the $52,400 with the $19,375 inputted into Appendix 2-A for the 4th Feeder for Cloutier Street in 2014.

Response: Yes, the 4th feeder goes along Ste-Therese and branches north onto Cloutier. Ste-Therese is connected to the substation while Cloutier connects to Ste-Therese.

CHEI has also indicated that the objective of this feeder switch is "to be prepare for the future growth in 2015 (south of Castor River 1,500 customers) and to reduce line lost on distribution system."

Preamble:

The utility and Load Flow Study done in 2011 showed that there were unbalanced currents on the existing Feeders 1 and 2 but especially Feeder 3. Keeping the currents in balance helps reduce line losses. Loading additions such as Feeder 4 is a good opportunity to rebalance the load.

d) Are these 1,500 new customers or existing customers or a mix of both? Please provide a breakdown. Response: all new residential. Planned for post 2014.

Response: The 1500 customer are all new customers.

e) Are the 1,500 customers noted here captured in CHEI's load forecast and customer forecast for the bridge year or test year?

Response: Only the 200 customers which are planned to be energized in 2014 have been factored into the Load Forecast. This is the best information available at this time.

2-Staff-18

Ref: E2.T2.S4 Historical and Projected Capital Plans – Pole Replacement Ste-Therese

– 4th Feeder

On page 25 of Exhibit 2, CHEI has estimated $54,800 in 2013 for installing a new pole to add the 4th feeder to prepare for the future growth in 2014 (south of Castor River).

a) Please confirm how many poles are being installed.

Response: Number of Poles are as such;

- Cloutier (2014); 3 poles are scheduled to be replaced in 2014 (total of $54,800)
- St-Therese (2013); 6 poles were replaced in June 2013 (total of $39,470)

b) Please provide a status update as to how many poles have been installed to date versus how many poles have been planned to be installed.

Response: see response to a) above.

c) Please confirm in which year all poles included in this project will be in service by. Response: 2014

Response: see response to a) above.

2-Staff-19

Ref: E2.T2.S5 page 38 Explanation of Expenses over the Materiality Threshold – Poles, Towers and Fixtures

On page 38 of Exhibit 2, the total costs of the poles and material for pole reframing on this page is $49,125. However, in Appendix 2-A and the 2013 Capital Budget table, on E2.T2.S3 page 23, indicates a total of $83,850 for these same components.

a) Please reconcile the difference and explain why there is a difference.

Response; The costs associated with account 1830 should have been $49,340 and costs associated with 1835 should have been $64,210. The total capital spending for both accounts remains $113,550. (See invoice from Sproule Powerline at the next page). CHEI notes that the $83,850 mentioned in the reference above is a total of ($29050+$54,800) however the $54,800 should have been $49,340.

This above change has no effect of the net book assets, depreciation expenses nor the Revenue Requirement Work Form. However, CHEI has made the change in the revised Board Appendices filed in conjunction with these replies.

b) Please explain how these amounts are related to the pole replacement projects for 2013 on page 25, which is also referred to in 2-Staff-21.

Response: Please see first page of Sproule Powerline invoices at the next page.

2013 Capital budget

GL ACT #	2013 CAPITAL PROJECTS DESCRIPTION	AMOUNT	
1820	GROUNDY STUDY SUBSTATION	$	10 000.00
	ADD NEW SWITCHING CABINET 4TH FEEDER	$	52 400.00
	SUB TOTAL	**$**	**62 400.00**
1830	REPLACE POLES, FIXTURES AS PER ASSET MANAGEMENT PLAN		
	NOTRE-DAME STREET REPLACE 2 POLES	$	10 400.00
	BOURDEAU CRESCENT REPLACE 1 POLE	$	4 200.00
	ST-JACQUES ROAD REPLACE 2 POLES	$	3 650.00
	BRISSON STREET REPLACE ONE POLE	$	3 000.00
	NOTRE-DAME STREET (DAMAGE POLE)	$	7 800.00
	SUB TOTAL	**$**	**29 050.00**
1830	STE-THÉRÈSE STREET 4T FEEDER 49 340.00	$	54 800.00
1835	STE-THÉRÈSE STREET 4T FEEDER 64 210.00	$	58 750.00
1845	UG CABLE SUBSTATION TO STE-THÉRÈSE	$	52 400.00
1850	TRANSFORMERS FOR REPLACING AND NEW SERVICES	$	12 000.00
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$	5 000.00
1915	CELL PHONE & EQUIPMENT	$	1,500.00
1920	COMPUTER EQUIPMENT AND HARDWARE BATTERY BACK-UP	$	1 500.00
1925	HARRIS SOFTWARE MOE STANDARD BILL PRINT	$	25 000.00
1925	ANTIVIRUS PROTECTION	$	1 500.00
	TOTAL	$	303 900 .00

SPL

SPROULE POWERLINE CONSTRUCTION LTD.

1420 County Road 10 West, Vankleek Hill, Ontario K0B 1R0
PHONE: (613) 678-2266 FAX: (613) 678-3081
E-mail: splmac@sympatico.ca

Cooperative Hydro Embrun Inc.
821 Notre-Dame, Suite #200
Embrun, ON K0A 1W1

PROPOSAL #2011-28-GM - Breakdown

Pole #1	Material required for pole reframing	$4,850.00	
	Labour to perform	4,500.00	
Pole #2	Material required for pole reframing	$5,665.00	
	Labour to perform	5,000.00	
Pole #3	New 55' foot Class 3 Pole	$1,485.00	
	Material required for new pole	3,000.00	8885
	Labour to perform	4,400.00	
Pole #4	Material required to reframe existing pole	$1,850.00	
	Labour to perform	4,500.00	
Pole #5	New 55' foot Class 3 Pole	$1,485.00	
	Material required for new pole	4,200.00	9865
	Labour to perform	4,400.00	
Pole #6	Material required to reframe existing pole	$3,000.00	
	Labour to perform	4,000.00	
Pole #7	New 55' foot Class 3 Pole	$1,485.00	
	Material required for new pole	3,300.00	8 985
	Labour to perform	4,200.00	
Pole #8	Material required to reframe existing pole	$3,200.00	
	Labour to perform	3,800.00	

PROPOSAL #2011-28-GM - Breakdown

Pole #9	New 55' foot Class 3 Pole………………………………	$1,485.00
	Material required for new pole ………………………	3,200.00
	Labour to perform………………………………………	4,800.00
Pole #10	Material required to reframe existing pole……………	$1,850.00
	Labour to perform………………………………………	3,200.00
Pole #11	Material required to reframe existing pole……………	$1,850.00
	Labour to perform………………………………………	3,200.00
Pole #12	New 55' foot Class 2 Pole………………………………	$1,900.00
	Material required for new pole ………………………	4,200.00
	Labour to perform………………………………………	6,000.00
Pole #13	Material required to reframe existing pole……………	$790.00
	Labour to perform………………………………………	1,317.00

9485.00

12100.00

Conductor – 3 x 640 metres of 336.4 KCML = 1920m @ 3.90/m…………………… $7,488.00

+ 3950.00

Material & Labour : $ 109,600.00 + HST

3950

113550.00

2-Staff-20

Ref: E2.T2.S5 Explanation of Expenses over the Materiality Threshold – Underground Conductors and Devices

On page 40 of Exhibit 2, CHEI estimated that the connection cost per house will be $1,200 for 250 houses for the new subdivision.

a) Please provide a detailed breakdown of how CHEI has estimated a $1,200 connection cost per house by each element of connecting (e.g. Feeders, smart meters, underground conductors, transformers, etc.).

Response: based on CHEI's estimated costs of new subdivition installation. A breakdown of the estimate is provided below.

Meters:	$150
transformer	$500
U/G cable	$300
feeders	$250
Total	$1,200

b) Why are the 4th Feeder for Ste-Therese in 2013 and the 4th Feeder for Cloutier Street not included in this estimated connection cost? Response:

Response: They are essentially two different projects. The $1,200 per connection covers the cost of energizing the subdivision (primary connection). Ste-Therese.and Cloutier are being done in advance of expected new growth and to optimize the system arrangement (cable sizes, load balancing, minimize losses and maximize voltage support).

2-Staff-21

Ref: E2.T2.S7 Asset Management Plan – Pole Replacement Schedule

On page 53 of Exhibit 2, CHEI has indicated that the pole replacements identified in red in the Poles Replacement Schedule table have been budgeted for in CHEI's 2014 cost of service application.

a) Please explain the rationale for why the replaced poles in 1999, 2004, 2011 and 2012 are being budgeted for in CHEI's 2014 cost of service? Response:

Response: As explained at page 53, the table shows how many poles need to be replaced per year based on when the poles were originally installed as opposed to poles that were installed in 1999. The 4 poles identified in 1999 are 54 years old (TUL of 40 + 14 years)

b) Why are the 2013 and 2014 years not included in the Poles Replacement Schedule table?

Response: The fact that there are no poles scheduled for 2013 and 2014 simply means that no poles were installed in 1973 and 1974 therefore no poles have reached their TUL in 2013 and 2014.

2-Staff-22

Ref: E2.T2.S7 Asset Management Plan – Inspection of Overhead Distribution System On page 57 of Exhibit 2, CHEI noted that the contractor provided an assessment of each poles' condition and subsequently made recommendations for pole replacements based on these attributes and condition, as per the annual inspection process.

a) Who is the contractor that carries out the pole inspection work for CHEI?

Response: Sproule Powerline Construction Limited carries out most of the operational work for CHEI.

b) Do CHEI's management and/or board of directors get involved in determining how many poles are replaced each year?

Response: Absolutely

c) Does this contractor also provide the inspection work for all other items in the minimum inspection requirements of the Distribution System Code?

Response: Yes they do. As mentioned earlier in these responses, the board members and general manager patrol the service area every week and do a visual inspection of the distribution system to ensure that all visible assets are working properly.

2-Staff-23

Ref: E2.T2.S8 Green Energy Act Plan

According to the 2014 Cost of Service Checklist completed by CHEI as part of its original application, CHEI is seeking an exemption from filing an OPA comment letter on the basis that the number of planned connections is immaterial.

a) Are the expenditures of the planned connections associated with CHEI's Green Energy Act Plan below CHEI's materiality threshold? Response:

Response. There are no expenditures associated with existing or planned microfit connections At the time of these responses, there are 8 existing connections and 4 pending connection.

b) Please confirm that CHEI has not submitted its Green Energy Act Plan to the OPA for comment. Response:

Response. That is correct, Given the small amount of connections in CHEI's service territory, the utility is of the opinion that the small amount of connections do not affect the proper functioning of the distribution system nor require any great planning process. Since CHEI is fully embedded with Hydro One, the utility will however obtain approval from Hydro One to ensure that their distribution system can accommodate the connection.

2.0-VECC – 3

Reference: Exhibit 2, Tab 2

a) Was an Asset Management Plan undertaken prior to the 2013 Plan? If yes please provide the forecast capital expenditures that were recommended in that plan.

Response: No, The DAMP was done in order to comply with the filing requirement.

b) If no previous plan was undertaken please provide the forecast capital expenditures for 2010 through 2013 that were included in the last cost of service application.

Response: In its 2010 Cost of Service Application, CHEI did not have to forecast its 2010 to 2013 expenditures. The test year was a reflection of the capital costs for the rate period of 2011-2013. Please see PDF at the next page for the 2010 Board Approved Capital Expenditures.

Coopérative Hydro Embrun Inc. (ED-2002-0493)

2010 EDR Application (EB-2009-0132) version: Draft Rate Order
Revised January 25, 2010

B3 Net Capital Asset Balances

Review projected capital asset account balances (no input on this sheet)

Account Description	2006 EDR Approved - Ending Balances			2006 Actual - Ending Balances		
	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value
1805-Land	50,000		50,000	50,000		50,000
1806-Land Rights						
1808-Buildings and Fixtures						
1810-Leasehold Improvements	1,404	-140	1,264			
1815-Transformer Station Equipment - Normally Primary above 50 kV						
1820-Distribution Station Equipment - Normally Primary below 50 kV	193,600	-23,662	169,938	195,423	-39,856	155,567
1830-Poles, Towers and Fixtures	365,418	-52,963	312,455	398,806	-91,429	307,377
1835-Overhead Conductors and Devices	363,163	-57,363	305,800	451,558	-100,633	350,925
1840-Underground Conduit						
1845-Underground Conductors and Devices	778,877	-94,388	684,489	884,334	-179,950	704,384
1850-Line Transformers	469,688	-62,974	406,714	508,585	-113,097	395,488
1855-Services	71,902	-5,365	66,537	109,085	-15,045	94,040
1860-Meters	71,464	-9,374	62,090	79,851	-17,171	62,680
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures						
1910-Leasehold Improvements						
1915-Office Furniture and Equipment	6,171	-1,520	4,651	24,122	-5,647	18,475
1920-Computer Equipment - Hardware	7,090	-4,101	2,989	12,115	-8,420	3,695
1925-Computer Software	4,396	-1,476	2,920	15,643	-7,861	7,782
1930-Transportation Equipment						
1935-Stores Equipment				4,320	-991	3,329
1940-Tools, Shop and Garage Equipment						
1945-Measurement and Testing Equipment	2,700	-990	1,710	4,281	-1,981	2,300
1950-Power Operated Equipment						
1955-Communication Equipment						

Coopérative Hydro Embrun Inc. (ED-2002-0493)

2010 EDR Application (EB-2009-0132) version: Draft Rate Order

Revised January 25, 2010

B3 Net Capital Asset Balances

Review projected capital asset account balances (no input on this sheet)

	2006 EDR Approved - Ending Balances			2006 Actual - Ending Balances		
1960-Miscellaneous Equipment						
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises						
1975-Load Management Controls - Utility Premises						
1980-System Supervisory Equipment						
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	-220,832		-220,832	-371,502	51,391	-320,111
2005-Property Under Capital Leases						
TOTAL	**2,165,041**	**-314,316**	**1,850,725**	**2,366,621**	**-530,690**	**1,835,931**

Coopérative Hydro Embrun Inc. (ED

2010 EDR Application (EB-2009-0132) version:
Revised January 25, 2010

B3 Net Capital Asset Balances

Review projected capital asset account ba

Account Description	2007 Actual - Ending Balances Gross Assets	2007 Accumulated Amortization	2007 Net Book Value	2008 Actual - Ending Balances Gross Assets	2008 Accumulated Amortization	2008 Net Book Value
1805-Land	50,000		50,000	50,000		50,000
1806-Land Rights						
1808-Buildings and Fixtures						
1810-Leasehold Improvements						
1815-Transformer Station Equipment - Normally Primary above 50 kV						
1820-Distribution Station Equipment - Normally Primary below 50 kV	197,522	-46,440	151,082	197,522	-53,025	144,497
1830-Poles, Towers and Fixtures	417,854	-108,142	309,712	436,177	-125,589	310,588
1835-Overhead Conductors and Devices	463,183	-119,160	344,023	536,674	-140,627	396,047
1840-Underground Conduit						
1845-Underground Conductors and Devices	939,067	-217,513	721,554	951,271	-255,563	695,708
1850-Line Transformers	560,586	-135,520	425,066	587,087	-159,004	428,083
1855-Services	131,544	-20,307	111,237	150,093	-26,310	123,783
1860-Meters	79,072	-20,334	58,738	79,072	-23,497	55,575
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures						
1910-Leasehold Improvements						
1915-Office Furniture and Equipment	28,964	-8,543	20,421	28,964	-11,439	17,525
1920-Computer Equipment - Hardware	14,198	-10,219	3,979	16,392	-12,219	4,173
1925-Computer Software	15,643	-10,658	4,985	15,643	-13,257	2,386
1930-Transportation Equipment						
1935-Stores Equipment	4,320	-1,426	2,894	4,320	-1,857	2,463
1940-Tools, Shop and Garage Equipment						
1945-Measurement and Testing Equipment	4,281	-2,409	1,872	4,281	-2,837	1,444
1950-Power Operated Equipment						
1955-Communication Equipment						

Coopérative Hydro Embrun Inc. (ED

2010 EDR Application (EB-2009-0132) version:
Revised January 25, 2010

B3 Net Capital Asset Balances

Review projected capital asset account ba

	2007 Actual - Ending Balances			2008 Actual - Ending Balances		
1960-Miscellaneous Equipment						
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises						
1975-Load Management Controls - Utility Premises						
1980-System Supervisory Equipment						
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	-464,616	69,976	-394,640	-486,899	89,452	-397,447
2005-Property Under Capital Leases						
TOTAL	**2,441,617**	**-630,695**	**1,810,922**	**2,570,596**	**-735,772**	**1,834,824**

Coopérative Hydro Embrun Inc. (ED

2010 EDR Application (EB-2009-0132) version:
Revised January 25, 2010

B3 Net Capital Asset Balances

Review projected capital asset account ba

Amounts from sheets B1 and B2

Account Description	2009 Projection - Ending Balances			2010 Projection - Ending Balances		
	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value
1805-Land	50,000		50,000	50,000		50,000
1806-Land Rights						
1808-Buildings and Fixtures						
1810-Leasehold Improvements						
1815-Transformer Station Equipment - Normally Primary above 50 kV						
1820-Distribution Station Equipment - Normally Primary below 50 kV	197,522	-59,609	137,913	197,522	-66,193	131,329
1830-Poles, Towers and Fixtures	470,477	-143,722	326,755	506,477	-163,261	343,216
1835-Overhead Conductors and Devices	555,174	-162,464	392,710	574,674	-185,060	389,614
1840-Underground Conduit						
1845-Underground Conductors and Devices	1,075,271	-296,094	779,177	1,295,556	-343,511	952,046
1850-Line Transformers	627,087	-183,287	443,800	662,087	-209,070	453,016
1855-Services	165,673	-32,625	133,048	193,838	-39,815	154,022
1860-Meters	79,072	-26,660	52,412	79,072	-29,823	49,249
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures						
1910-Leasehold Improvements						
1915-Office Furniture and Equipment	30,964	-14,435	16,529	34,964	-17,731	17,232
1920-Computer Equipment - Hardware	21,392	-15,997	5,395	25,392	-20,675	4,717
1925-Computer Software	77,843	-22,605	55,238	78,843	-38,273	40,570
1930-Transportation Equipment						
1935-Stores Equipment	4,320	-2,289	2,031	4,320	-2,721	1,599
1940-Tools, Shop and Garage Equipment						
1945-Measurement and Testing Equipment	4,281	-3,265	1,016	4,281	-3,693	588
1950-Power Operated Equipment						
1955-Communication Equipment						

Coopérative Hydro Embrun Inc. (ED

2010 EDR Application (EB-2009-0132) version:

Revised January 25, 2010

B3 Net Capital Asset Balances

Review projected capital asset account ba

Amounts from sheets B1 and B2

	2009 Projection - Ending Balances			2010 Projection - Ending Balances		
1960-Miscellaneous Equipment						
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises						
1975-Load Management Controls - Utility Premises						
1980-System Supervisory Equipment						
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	-570,099	110,592	-459,507	-690,099	135,796	-554,303
2005-Property Under Capital Leases						
TOTAL	**2,788,976**	**-852,460**	**1,936,516**	**3,016,926**	**-984,032**	**2,032,895**

2.0-VECC – 4

Reference: Exhibit 2, Tab 1, pg.9 (E2.T1.S3)

a) Please provide a description of the Intangible Plant (account 1300) and the reasons for its growth from $0 in 2009 to $146,427 (forecast) in 2014.

Response: Account 1611-Computer Software (formally account 1925) fall under the grouping of intangible Plant. The 2009 balance for computer software can be found in account 1925.

2.0-VECC – 5

Reference: Exhibit 2, Tab 2. Schedule 2 – Appendix 2-A

a) Please explain the reasons for the inordinately low capital spending in 2012 as compared to the previous and post period.

Response: The distribution system is well maintained and requires little capital expenditure to maintain. The year over year increase is largely linked to new development which were scarce in 2011 and 2012

2.0-VECC – 6

Reference: Exhibit 2, Tab 2 (E2.T2.S3)

a) Please provide the capital budgets for all connection projects (actual and forecast) for the years 2009 through 2014.

Response: See table below

GL ACCOUNT	2009	2010	2011	2012	2013	2014
1820	$0.00	$22,389.72	$0.00	$0.00	$10,000.00	$0.00
		$2,576.00			$52,400.00	
1830	$43,906.50	$62,255.50	$18,096.52	$3,098.10	$29,050.00	$20,750.00
					$54,800.00	$39,470.00
1835	$5,232.00	$856.00	$4,224.00	$0.00	$58,750.00	$19,375.00
1845	$875.00	$0.00	$5,841.00	$0.00	$52,400.00	$398,000.00
1850	$73,966.10	$28,327.65	$21,553.50	$36,088.00	$12,000.00	$87,500.00
1855	$11,372.75	$12,636.50	$4,036.25	$5,074.00	$5,000.00	$4,000.00
1860	$0.00	$0.00	$0.00	$310,212.00	$0.00	$30,500.00
Stranded meters				-$79,072.00		
1995 (cap Contribution)	$0.00	-$11,423.00	-$7,774.00	-$1,600.00	-$8,000.00	-$160,000.00

2.0-VECC – 7

Reference: Exhibit 2, Tab 1 (E2.T1.S6)

a) Does Embrun monthly or bimonthly all its customers? Is the current billing cycle practice different, and how, from that used in 2009.

Response: Since 2011, Embrun now bills all of its customers on a monthly basis. Prior to 2011, CHEI billed its residential customers on a bi-monthly basis and all other classes on a monthly basis.

b) Please calculate the reduction in revenue requirement that would be associated with a 12% working capital allowance.

Response: $2,346.

2.0-VECC – 8

Reference: Exhibit 2, Tab 2, pg.23, Table 2013 Capital Budget

a) Please update the 2013 capital budget table by adding three new columns showing actual spent –to-date, estimated remaining to be spent to year-end, and estimated or actual in-service date.

Response; See table below.

GL ACT #	2013 CAPITAL PROJECTS DESCRIPTION	AMOUNT	ACTUAL SPENT	REMAINING TO SPENT	ESTIMATED OR ACTUALT IN SERVICE DATE
1820	GROUNDY STUDY SUBSTATION	$ 10 000.00	$ 10 000.00	$ 0.00	MARCH 2013
	ADD NEW SWITCHING CABINET 4TH FEEDER	$ 52 400.00	$ 52 400.00	$ 0.00	JUNE 2013
1830	REPLACE POLES, FIXTURES AS PER ASSETMANAGEMENT PLAN				
	NOTRE-DAME STREET REPLACE 2 POLES	$ 10 400.00			
	BOURDEAU CRESCENT REPLACE 1 POLE	$ 4 200.00	$ 4 200.00	$ 0.00	MAY 2013
	ST-JACQUES ROAD REPLACE 2 POLE	$ 3 650.00	$ 3 650.00	$ 0.00	APRIL 2013
	BRISSON STREET REPLACE ONE POLE	$ 3 000.00	$ 3 000.00	$ 0.00	APRIL 2013
	NOTRE-DAME STREET – DAMAGE POLE	$ 7 800.00	$ 7 800.00	$ 0.00	MAY 2013

	STE-THÉRÈSE STREET 4T FEEDER	$ 54 800.00	$ 54 800.00	$ 0.00	JUNE 2013
1835	STE-THÉRÈSE STREET 4T FEEDER	$ 58 450.00	$ 58 450.00	$ 0.00	JUNE 2013
1845	UG CABLE SUBSTATION STE-THÉRÈSE	$ 52 400.00	$ 52 400.00	$ 0.00	JUNE 2013
1850	TRANSFORMERS FOR REPLACING AND NEW SERVICES	$ 12 000.00	$ 4 042.50	$ 7 957.50	BY END OF 2013
1855	NEW O.H AND UG SERVICES MATERIALS AND LABOUR	$ 5 000.00	$ 5 975.00	$ 2 500.00	BY END OF 2013
1915	CELL AND EQUIPMENT	$ 1 500.00	$ 960.00	$ 540.00	BY END OF 2013
1920	COMPUTER EQUIPMENT	$ 1 500.00	$ 2 085.00	$ 0.00	MARCH/AUGUST 2013
1925	ANTIVIRUS PROTECTION	$ 1 500.00	$ 500.00	$ 1 000.00	BY END OF 2013
1925	HARRIS SOFTWARE MOE STANDARD BILL PRINT	$ 25 000.00	$ 0.00	$ 25 000.00	BY END OF 2013
1995	CONTRIBUTE CAPITAL	$ 8 000.00	$ 3 000.00	$ 5 000.00	BY END OF 2013

2.0-VECC – 9

Reference: Exhibit 2, Tab 2, pg. 30,37

Preamble The utility anticipates load growth in the next few years due to the building of several subdivisions. At the time of this application only one subdivision is planned. (pg.37)

a) Please provide the status of subdivision projects: Patenaue Subdivision (100 units), Brisson Project Oligo (50 units), Domain Versaille (50 units), and Maurice Lemiux (50 units). In this update please indicate when (or if) service has been laid out in the subdivision, when (or if) building construction has started and the actual or expected construction completition date.

Response: CHEI notes that there has been delays in due to financial negotiations between the town and the developer. The two parties have reached an agreement and at the time of these responses, the township maintains that the 4 subdivisions will be in service by the end of 2014.

- Patenaude Subdivision;
  - 139 units
  - Preliminary Design have been received
  - lot has been cleared.
  - In service date by the end of 2014

- Brisson Project OLIGO
  - 38 units
  - Preliminary Design have been received
  - In service date by the end of 2014

- Domaine Versaille:
  - No update since the application

- Maurice Lemieux
  - No update since the application

b) Please indicate for each project whether service is overhead or underground.

Response underground

c) Please provide the current estimated cost to serve each subdivision and the expected contribution in aid-of construction for each sub-vision and the current expected occupancy date for the subdivision.

Response: Actual costs are still pending. CHEI has estimated the cost per connection to be $1,200. This estimate was derived from the cost of the last subdivision done in 2004 along with input from Sproule Powerlines Construction Limited.

2.0- VECC - 10

Reference: Exhibit 2, Tab 3, Appendix C – System Load-Flow and Optimization Study

a) Beginning at page 14 of the Study there is a discussion of the need for substation redundancy and capacity and which includes 3 options to address the risks identified. Please explain which option Embrun is pursuing and the capital budget (year and amount) for addressing the issue.

Response: Based on the recommendations from Stantec, the Manager and Board of Director chose Option #2 which was to build a new substation. On behalf of CHEI, Stantec sent an RFP' to 5 potential contractors. The lowest quote was $715,000. Depending on new growth in the service area, CHEI hopes to build the substation in 2018.

Exhibit 3 – Operating Revenue

3-Staff-24

E3.T1.S4 Load Forecast – Customer Forecast

On page 19 of Exhibit 3, CHEI has indicated that it is in the process of upgrading its distribution system to accommodate new development and that it plans to energize this new subdivision sometime in 2014-2015. CHEI also estimated that the natural growth of the Residential class will increase by 1.26% over 2012 for both 2013 and again in 2014.

a) Please provide the methodology used and the source of data supporting the estimate.

Response: Please see response to e) below

b) Please provide an update to the status of this new subdivision (i.e. are there any updates from the municipality?)

Response: As mentioned earlier in these responses, financial negotiations between the municipality and developer caused some delays however the municipality maintains that the expected in-service date for the 4 subdivisions is end of 2014.

c) When are CHEI's key milestone dates in relation to the construction of the subdivision?

Response: This information resides with the municipality and developers and has not been communicated with the utility.

d) Does the subdivision plans still expect an additional 300 residential and small business customers? If so, please provide the breakdown between the difference customer classes by customer count and by load.

Response: This information was clearly provided at Section E3.T1.S4 (or page 22 and 23 of Exhibit 3) of the Exhibit 3. The utility still expects the following load and customer growth for 2013 and 2014 for the residential class. CHEI Notes that this information is still the best known information available at this time.

Residential				
Year	New Customer	Per Customer Weather Normalized (based on 2012 Cust count)	Added Load	Total
2013	10	10,916	109,165	**19,627,850**
2014	200	10,959	2,191,747	**21,785,963**

And expects the following load and customer growth for the GS<50 Class.

GS<50				
Year	New Customer	Per Customer Weather Normalized	Added Load	Total
2013	3	30,031	90,093	**4,804,973**
2014	11	30,147	331,620	**5,064,745**

e) Please reconcile the natural growth that CHEI has estimated to be 1.26% for the residential rate class for 2013 and 2014 with the approximate increase of 10.8% for the residential rate class (2012 versus 2014) load forecast in Table 1: Proposed 2014 Load Forecast in E3.T1.S2.

Response: The 1.26 (should have been 1.026) originates from Table 13-Customer Forecast which predicts a Geomean of 1.026 for the residential class. The Geomean is calculated based on historical growth and then applied to 2013 and 2014 in order to determine the forecasted customer counts. As explained at page 19 of Exhibit 3, CHEI anticipates that a new subdivision will be energized sometime in 2014-2015. This subdivision would include approximately 300 houses. The utility, the municipality and board members are of the opinion that it is unlikely that all 300 units will be completed, sold and energized in 2014. For this reason, CHEI has adjusted its proposed customer count to add in 200 new customers in the residential class. The use of Geomean is the best know methodology available to determine customer growth.

3-Staff-25

Ref: E3.T1.S4 – Customer Forecast

On page 26, CHEI provides Table 18 which presents the actual and forecast kWh and kW for Street Lighting and Unmetered Scattered Load classes. However, it appears that the table has not included the column “Year” to identify the time period. Please provide an updated Table 18 with the proper corresponding time period.

Response: The updated table is provided at the next page

Table 18- non-weather sensitive Street Lighting, USL

	Streetlight						USL		
Year	Energy	Demand	Connection	kWh per connection	KW per connection	KW/kWh Ratio	Energy	Connection	kWh per connection
2003	310,985	856	381	816	2.2467	0.00275	66,312	15	4,421
2004	344,131	908	387	889	2.3466	0.00264	66,312	15	4,421
2005	370,312	951	395	937	2.4084	0.00257	66,312	15	4,421
2006	381,159	955	395	965	2.4173	0.00251	66,312	15	4,421
2007	379,503	987	409	928	2.4125	0.00260	88,330	21	4,206
2008	388,274	1,007	409	949	2.4616	0.00259	93,536	19	4,923
2009	350,654	1,003	409	857	2.4528	0.00286	92,676	19	4,878
2010	381,018	1,003	409	932	2.4528	0.00263	89,786	19	4,726
2011	357,291	1,003	409	874	2.4528	0.00281	89,208	19	4,695
2012	355,537	1,003	409	869	2.4528	0.00282	89,208	19	4,695
2013	374,202	1,000	415				91,612	20	
2014	383,219	1,024	425				91,612	20	
Avg				*902*	*2.4104*	*0.00268*			*4,581*

3.0-VECC – 11

Reference: Exhibit 3

Preamble: *Embrun filed a revised Application in July 2013 and then filed a further revised version on September 12, 2013*

a) Please confirm that there were no changes to Exhibit 3 in the September filing. If there were, please indicate what they are.

Response: CHEI confirms that the Load Forecasting information filed in in the original application on May 10th 2013 is still the most up to date information available.

3.0-VECC – 12

Reference: Exhibit 3, Tab 1, page 5-7 (July 2013)
Load Forecast Worksheet, Input Customer Growth Tab
Load Forecast Worksheet. Final Load Forecast Tab

a) Are the customer count values reported in Table 1 year end or average annual values?

Response: Year-end values. CHEI believes that a year-end customer count is more representative of the expected revenues from 2015 to 2018. Using a year-end customer count is also consistent with the year-end consumption that is being used to determine the Load Forecast.

b) The Application (page 7) states that the USL customer count is increasing as a result of the new subdivision. However, the 2014 forecast customer count is the same as for 2013. Please reconcile.

Response: The use of the Geomean to determine the growth in USL forecasted 1 new connection in 2013. CHEI notes that this forecast is consistent with the prediction of a new USL required as a result of the new subdivisions being energized. CHEI expected the USL to be in service at the end of end of 2013.

f) What was the actual customer count by class for most recent month where data is available?

Response:

- Res: 1791
- GS<50: 159
- GS>50: 11
- USL: 19
- Streetlights: 407 connections

3.0 – VECC – 13

Reference: Exhibit 3, Tab 1, page 13 (July 2013)

Preamble: The Board's Filing Guidelines issued July 2013 (Chapter 2, page 23) require that distributors file test year load forecasts based on: "a) 10-year average and b) 20-year trend HDD and CDD".

a) Please provide a schedule that compares the forecast 2014 purchases (prior to any CDM adjustment) based on i) the 10-year average CDD and HDD values with ii) the 20-year trend HDD and CDD.

Response: This information is unfortunately not readily available and would require additional time and effort to obtain.

3.0 – VECC – 14

Reference: Exhibit 3, Tab 1, page 14 (July 2013)
Load Forecast Worksheet, Input WS Regression Analysis Tab
2013 Ontario Budget
(http://www.fin.gov.on.ca/en/budget/ontariobudgets/2013/)

a) What is the basis for the employment level forecast used for 2013 and 2014?

Response: CHEI used the reported in Statistics Canada's Monthly Labour Force Survey for the Ottawa region for historical inputs. The 2013 and 2014 were determined based on a 10 year average of these inputs.

b) The employment levels forecast for 2013 and 2014 are lower than those for 2012. However, the 2013 Ontario Budget (Table 2.6) calls for provincial employment increases in 2013 and 2014 of 1.2% and 1.4% respectively. Please reconcile.

Response: The budget was made public on May 2nd 2013 after the filing deadline of April 30th 2013. Although CHEI filed its application 10 days past the deadline, clearly, CHEI did not factor those inputs into their Load Forecast. CHEI notes that this question would be better suited for an October filer than an April filer.

c) Please provide a revised forecast using the same equation but where the actual 2012 monthly employment levels are increased by the percentage amounts in the 2013 Budget. Please also provide the revised Load Forecast Worksheet.

Response: As indicated in the link provided above (table replicated below) the increase of 1.2% and 1.4% applies to 2013 and 2014 respectively. Applying these increases to 2012 data would be incorrect. Also, the use of the economic outlook as a parameter may not be as indicative as VECC may think. In 2011, the outlook predicted an increase of 1.8% while the full time employment in for the Ottawa region dropped by 0.6%.

Ontario Economic Outlook (Per Cent)

	2010	2011	2012	2013p	2014p
Real GDP Growth	3.2	1.8	1.6	1.5	2.3
Nominal GDP Growth	5.2	4.7	2.9	3.0	4.1
Employment Growth	1.7	1.8	0.8	1.2	1.4
CPI Inflation	2.5	3.1	1.4	1.5	2.0

In order to respond to VECC's question, CHEI has applied the 1.4 to 2012 and shown the results of the regression at the next page.

SUMMARY
OUTPUT

Regression Statistics	
Multiple R	0.931698484
R Square	0.868062066
Adjusted R Square	0.863432665
Standard Error	165571.2076
Observations	119

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	2.06E+13	5.14E+12	187.5107	3.67E-49
Residual	114	3.13E+12	2.74E+10		
Total	118	2.37E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	776102.9318	294085	2.639043	0.009477	193522.8	1358683	193522.8	1358683
977.3	1380.69845	76.03169	18.15951	1.96E-35	1230.08	1531.317	1230.08	1531.317
0	2184.295728	629.2935	3.471029	0.000733	937.6702	3430.921	937.6702	3430.921
0	- 320025.5865	36759.28	-8.70598	2.8E-14	-392845	-247206	-392845	-247206
486.5	2432.463403	534.2117	4.553369	1.33E-05	1374.194	3490.733	1374.194	3490.733

3.0 – VECC – 15

Reference: Exhibit 3, Tab 1, pages 21-27 (July 2013)

a) With respect to Table 19, what is the total kWh for all customer classes expressed as a percentage of weather adjusted purchases for each year from 2010-2014?

Response:

Weather Adjusted Purchases vs Total kWh Forecasted

	Total kWh Forecasted	Weather Adj Purchases	%
Year			
2010	29,032,693	29,936,866	0.97
2011	28,442,070	29,778,753	0.96
2012	29,855,632	30,483,513	0.98
2013	29,166,148	29,540,520	0.99
2014	31,609,564	29,654,833	1.07

3.0 – VECC – 16

Reference: Exhibit 3, Tab 1, pages 28-31 (July 2013)
Board Decision and Order re: Centre Wellington Hydro's 2013 Rates (EB-2012-0113), pages 6-7

Preamble: The Board's Filing Guidelines issued July 2013 (Chapter 2, pages 24-25) state:
Further, the actual results for 2011 and 2012 historical years, which will, in all likelihood, be used to develop the base forecast, includes the impacts of 2011 and 2012 CDM programs. The CDM adjustment to the load forecast should also take into account the historical CDM results factored into the base load forecast before the CDM adjustment, in order to avoid double counting of the impacts. ".

a) Please confirm that Embrun's proposed 710,140 kWh adjustment for CDM includes 537,910 kWh associated with CDM savings achieved in 2011 and 2012.

Response: CHEI believes this statement to be correct

b) In accordance with the Board's Guidelines, please confirm that these savings should be removed as part of the "manual adjustment" since they are already reflected in the actual purchased power values used to develop the initial load forecast.

Response: CHEI believes this statement to be correct

c) In its Decision regarding Wellington Hydro's 2013 rates the Board rejected the use of a net-to-gross adjustment factor and required that the CDM adjustment be done on a "net" basis. The Board also directed that the impact in the first year of a CDM program be adjusted using the "half-year rule".
   - Please recalculate the manual adjustment for 2014 so as to exclude the impact of 2011 and 2012 CDM programs and so as to be consistent with the Board's direction in the Centre Wellington Decision.
   - Please confirm that the resulting value should be 58,322 kWh (i.e. 38,881 + (0.5 * 38,881)).

Response: CHEI believes this value stated above is consistent with its own calculations. (as presented in the revised CDM Forecast sheet in the Appendices (partly reproduced below)

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2014)

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B29 to

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C30 to E30.

Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

		4 Year (2011-2014) kWh Target:			
		1,200,000			
	2011	2012	2013	2014	Total
2011 CDM Programs	5.91%	5.90%	5.90%	5.89%	23.61%
2012 CDM Programs		20.00%	20.00%	20.00%	60.00%
2013 CDM Programs			3.24%	3.24%	6.48%
2014 CDM Programs				3.24%	3.24%
Total in Year	**5.91%**	**25.90%**	**29.14%**	**32.37%**	**93.33%**
		kWh			
2011 CDM Programs	70,950.86	70,848.70	70,848.70	70,709.46	283,357.71
2012 CDM Programs		240,000.00	240,000.00	240,000.00	720,000.00
2013 CDM Programs			38,880.76	38,880.76	77,761.53
2014 CDM Programs				38,880.76	38,880.76
Total in Year	**70,950.86**	**310,848.70**	**349,729.46**	**388,470.99**	**1,200,000.00**

	2011	2012	2013 kWh	2014	Total for 2014
Amount used for CDM threshold for LRAMVA (2014)	70,709.46	240,000.00	38,880.76	38,880.76	388,470.99
Manual Adjustment for 2014 Load Forecast (billed basis)	-	-	38,880.76	19,440.38	58,321.15
Proposed Loss Factor (TLF)	1.07%	Format: X.XX%			
Manual Adjustment for 2014 Load Forecast (system purchased basis)	-	-	39,295.31	19,647.66	58,942.97

3.0 – VECC – 17

Reference: Exhibit 3

a) Please confirm what changes, if any, Embrun is proposing to its 2014 load forecast based its responses to both Board Staff's and VECC's interrogatories and provide a schedule setting out the revised proposed load forecast (customer count, kWh and kW (where applicable) by customer class and the supporting Load Forecast Worksheet.

Response: In compliance with page 69 of the RRFE report (published on October 18, 2012) which state;

> "For distributors scheduled to rebase for 2014 and planning to seek the Board's approval for January 1 rates, there will be two options available:
>
> 1) <u>Rebase under 3rd Generation IR filing requirements</u> (in other words, without the 5 year capital plan) and remain under IR for 4 years total (rebasing plus 3 years) with rates adjusted annually using the 4th generation IR annual Adjustment"
> 2) Delay rebasing by one year - rebase for January 1, 2015 rates, in which case the application will be filed using the Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements, and the total term will be 5 years.

By filing in April of 2013, CHEI essentially adopted Option 1) which was to file its application under 3rd generation IRs filing requirement. CHEI would like to make it clear that scenarios prepared as responses to VECC's IRs do not in any way imply a commitment on CHEI's part to adopt these changes.

Unless specifically directed by the OEB in its decision and order, the utility is not proposing or committing to updating any of its Load Forecast information to reflect requirements that were issued on July 17 of 2013 – 2 months after CHEI's application was filed.

CHEI wishes to comply with Board policy and as such maintains that it has complied with Board policy on all aspects of the 3rd generation IRs filing requirements. It is CHEI's understanding that it was the OEB who introduced the net-to-gross adjustment in the first place. If the OEB has adopted a different approach, as a result of the Wellington North decision, it should simply provide utilities, including CHEI, with direction on how to calculate and apply the CDM adjustment.

Exhibit 4 – Operating Costs

4-Staff-26

Ref: E4.T2.S1 Variance Analysis – Salary and Wages

On page 33 under Exhibit 4, CHEI has indicated a 6% variance in salaries and wages for the 2014 Test Year.

a) Please provide reasons as to why this variance is higher than what CHEI has experienced in the past. Response: Word document

Response:

As explained in CHEI ‘s June 13, 2013 revision, CHEI does not use specific benchmarking studies to determine salary ranges. However CHEI and its shareholder are well aware of the salary ranges in neighbouring utilities and use the neighbouring salaries as a guideline. CHEI is also aware of recently published surveys and attests that current salaries are well below those suggested salary range. Periodically, the utility’s Board of Director along with management input will readjust employee salary to be in line with it neighbouring cohorts.

In December of 2012, CHEI’s Board of Directors approved a new wage scale and approved salaries for the period of 201-2018. The table is presented below. (Please note that decisions related to compensation adjustments reside fully with the Board of Directors and not the Manager.) CHEI would also like to note the last salary adjustment was done in 2010.

2014	2015	2016	2017
6%	1.15%	3.4%	3.25%

b) Please also provide CHEI’s sources in determining appropriate salaries. Response: see Word document

Response: http://www.travailleraucanada.gc.ca/recherche_salaires-perspectives-fra.do?reportOption=wage

4-Staff-27

Ref: E4.T2.S2 Appendix 2-K Employee Compensation – Incentive Pay

CHEI has not included any amounts for incentive pay for the 2013 Bridge year and 2014 Test year, however, average yearly incentive pay for 2011 and 2012 actuals were $15,957 and $19,000 respectively.

a) Please explain the rationale for not including any incentive pay amounts for 2013 and 2014.

Response: In the 3rd Generation Appendices, the table specifically excluded bonus and incentives from the eligible total. CHEI therefore assumed that the incentives were not eligible for inclusion in the Revenue Requirement. If the amounts are eligible, CHEI request the right to include in it Revenue requirement

b) Please also explain why there was no incentive in 2010?

Response: Below are the incentives paid out by year.

2010	2011	2012
$ 15 957.42 (BASED ON 10% OF GROSS SALARY) PAID IN APRL 2011	$ 15 000.00 ($ 5 000.00 PER EMPLOYEES) PAID BEGINNING OF 2012	$ 9000.00 ($ 3 000.00 PER EMPLOYEES) PAID END OF 2012

c) Are incentive payouts made to all employees at CHEI or to a specific group only (i.e. Management and/or Board of directors)?

Response: Incentives are paid out to all 3 employees.

4-Staff-28

Ref: E4.T7.S2 LRAMVA

On page 53 under Exhibit 4, CHEI has provided its LRAMVA calculations in a series of tables. CHEI has included net CDM energy (kWh) and peak demand (kW) savings for both 2011 programs and 2011 program savings persisting into 2012 in its LRAMVA calculations.

a) Please provide an updated LRAMVA Rate Rider table that only includes LRAMVA amounts for 2011 program savings in 2011 and does not include any 2011 persisting savings in 2012.v

Response:

LRAMVA Calculations

	2011	2012	2013	
LRAM Claim (kW):	52			tab 3.1.1 of Final 2011 OPA report
LRAM Claim (kWh):	70,951			tab 3.1.1 of Final 2011 OPA report

Per class allocation (kWh)	2011 Alloc by Class	2012 Alloc by Class	2011 LRAM (kWh)	2012 LRAM (kWh)	Total
Residential	69%	67%	48,624	-	48,624
General Service < 50 kW	16%	16%	11,259	-	11,259
General Service > 50 to 4999 kW	14%	15%	9,954	-	9,954
Unmetered Scattered Load	0%	0%	223	-	223
Street Lighting	1%	1%	891	-	891
	100%	**100%**	**70,951**	**-**	70,951

Per class allocation (kW)	2011 Alloc by Class	2012 Alloc by Class	kW	kW	Total
General Service > 50 to 4999 kW	92%	93%	48	-	
Street Lighting	8%	7%	4	-	
			52	**-**	

LRAMVA Rate Rider	2011 Volumetric Rate	2012 Volumetric Rate	2011 LRAM	2012 LRAM	Entry to 1568
Residential	0.0126	0.0128	$612.66	$0.00	$612.66
General Service < 50 kW	0.0166	0.0168	$186.90	$0.00	$186.90
General Service > 50 to 4999 kW	4.4833	4.5445	$216.55	$0.00	$216.55
Unmetered Scattered Load	0.0103	0.0104	$2.29	$0.00	$2.29
Street Lighting	6.4268	6.5145	$26.25	$0.00	$26.25
			$1,044.66	**$0.00**	**$1,044.66**

b) Please discuss if CHEI will be updating its application to include a request for approval of its 2012 LRAMVA amounts related to its 2012 OPA Province-Wide CDM Programs. If CHEI plans on updating its application, please discuss when it will do so.

Response: CHEI plans to update its LRAMVA in its draft rate order.

4-Staff-29

Ref: E4.T9 Patronage Dividends

On page 49 under Exhibit 4, since 2001 CHEI has remitted over $300,000 to its customer of which $100,000 was in the last three years. CHEI noted that this amount of dividends more than offsets the increase in costs from 2010 to the proposed Test Year.

a) Please provide the calculation CHEI uses in determining the amount of patronage dividend to pay out to its members.

Response: The Board of Directors reviews the audited financial statements along with capital and operating budgets and essentially decides on a remittance. The decision is not based on calculation but more so on a review of the previous year's net income and upcoming projects.

	2012	2011
before income	212209	148167
patronage refund	55708	24018
	26%	16%

b) Please also describe in detail what factors are involved in determining what each member receives (e.g. is the dividend payout calculated on electricity consumption?).

Response: The Cooperative choses to give back to its shareholder – in this case the customers, the same way that other utilities give dividends to their municipality. The great thing about cooperatives is that patronage dividends serves to ultimately reduce the customer's electricity bills. CHEI is very interested in seeing if other utilities will be as diligently scrutinized on the dividends paid to their shareholder as CHEI was.

c) Who has the ultimate decision to decide to pay out the patronage dividend? Are members involved in this decision? If not, why not?

Response: see response to a) which says that the Board of Director ultimately decides on the patronage dividends. CHEI notes that the Board of Director represents the members of the cooperative and therefore the customer decides how much is given back in dividends. Patronage dividends are addressed and discussed and approved at the annual members meeting.

d) Is there a threshold used in the calculation to determine whether or not a dividend will be paid out? If so, what is it?

e) What does CHEI forecast on paying out for 2013, 2014 and 2015?v

Response to d) e): If a loss occurs, the cooperative will not pay out patronage dividends. As long as there is a net profit, the utility will make every attempt to return some profits to its members. The amount given out is solely dependent on the profits of the previous year therefore the Cooperative does not forecast in advance what the payout will be. Instead waits for the financial statements to be audited and makes an executive decision on the amount that will be remitted.

4.0 - VECC- 18

Reference: Exhibit 4, Tab 1, Schedule 3/ Appendix 2-H CHEI 2014 OEB Appendics_2013014

a) Please reconcile the 2010 OM&A from these two sources ($469,199 in the Excel spreadsheet vs. $497,227 in the test source)

Response: As the headings clearly indicate. Appendix 2-G shows a total of $469,199 for <u>2010 Actuals</u> while Appendix 2-H shows a total of $497,227 for <u>2010 Board Approved</u>

4.0 - VECC- 19

Reference: Exhibit 4, Tab 1, pg.6

a) Please provide the derivation of the incremental $34,500 identified as on-going incremental costs for smart metering. In this analysis please identify the cost of meter reading pre and post installation of smart meters.

Response: The $34,500 should have read $31,400 which is consistent with the evidence presented at page 23.

- Meter Reading 2008: $11,464 manual read
- Meter Reading 2009: $10,313 manual read
- Meter Reading 2010: $3,303 mass communication which includes ($1048) and smart meter phones lines.(2255) note that MDMR costs are not included in this amount
- Meter Reading 2011: same as 2010
- Meter Reading 2012: 1 same as 2010

Note that meter reading expenses are included in billing and collecting and not meter costs.

4.0 - VECC- 20

Reference: Exhibit 4, Tab 1, pg. 21

a) Embrun has significantly increased its allowance for bad debt and collection charge expense in 2014 (e.g. $2,314 in 2012 vs. 8,200 in 2014). Embrun explains that changes to OEB rules have resulted in the Utility discontinuing security deposits. Please explain the basis for the assumption that the lack of security deposits will increase bad debt and collection costs (for example, in the last year security deposits were held what amount was drawn against them for non-payment).

Response: Without security deposits the customer has little incentive to pay their last bills. CHEI notes that in the past provision for bad debt was included in account 1130 accumulated provision for uncollected account – credit. In the past, these provisions were never included in rates as account 1130 is not a ratemaking account. CHEI has now included projection of 5000 in both 2013 and 2014 in account 5335 which is recoverable through rates.

Amounts held

Account	2014	2013	2012	2011	2010	2009
5335			0	3850	3850	3850
1130	5000	5000				

Amounts applied

2012	2011	2010	2009
3850	0	0	0

At September 30 2013, the balance of account 5335 was;

.

Accounts 30days - 60days overdue; $3,339
Accounts 61days – 90days overdue: $881
Accounts over 91days overdue: $2,371.79

4.0 - VECC- 21

Reference: Exhibit 4, Tab 1

a) Please provide association fees paid to the EDA for each of the years 2010 through 2014 (forecast).

Response:

YEAR	EDA FEES
2010	$ 4 700.00
2011	$ 4 850.00
2012	$ 5 120.00
2013	$ 5 300.00
2014	$ 5 600.00

b) Separately provide and describe the cost of all other association memberships.

Response: CHEI has no other association membership costs.

4.0 - VECC- 22

Reference: Exhibit 4, Tab 1

a) Account 5605 – Executive Salaries and Expenses has increase 47% since 2010 as compared to 2014 forecast. Please explain the reasons for this. Specifically please address the increase in total salaries from $166,172 to $176,106 (6%) between 2013 and 2014.

Response: This account only includes compensation for the Board of Directors. Aside from the cost of living applied to the compensation, the increase between 2011 and 2014 is due to additional responsibilities which were assigned to Board members starting in 2011. As mentioned earlier, the Board of Director patrol service area on a weekly basis. Over the past 2 years, the Board of Directors have been involved in numerous unplanned meetings to address the new growth, new subdivision and additional feeders to accommodate the expected growth. It's also important to mention that the Board of Directors is very involved in the utility and its customers. The Board of Director also meets with the auditors and consultants (such as Tandem Energy Services Inc.) on a regular basis.

b) Similarly Account 5615 – General Administrative Salaries has increased by 76% since 2010. Please provide the reasons for this large increase.

Response: CHEI has provided a breakdown of the yearly entries to this account. All increases are warranted and necessary. The main drivers behind the increase is the DSPS and the conference and seminars which are difficult to reduce since .

Year	DESCRIPTION	AMOUNT
2010	Bank Charge	$ 345.00
	Transportation	$ 4,140.00
	Annual Meeting	$ 2,068.00
	Membership EDA	$ 4,700.00
	DPSP	$ -
	WSIB	$ 1,800.00
	Payroll Remittance - CPP-EI	$ 9,155.00
	Benefit	$ 12,011.00
	Conference/Seminar	$ 4,170.00
		$ 38,389.00
2011	Bank Charge	$ 485.00
	Transportation	$ 4,516.00
	Annual Meeting	$ 521.00

	Membership EDA	$ 4,850.00
	DPSP	$ 5,566.00
	WSIB	$ 2,022.00
	Payroll Remittance - CPP-EI	$ 9,967.00
	Benefit	$ 13,441.22
		$ 41,368.22
2012	Bank Charge	$ 486.00
	Transportation	$ 4,516.00
	Annual Meeting	$ 521.00
	Membership EDA	$ 4,850.00
	DPSP	$ 5,566.00
	WSIB	$ 2,022.00
	Payroll Remittance - CPP-EI	$ 9,967.00
	Benefit	$ 18,747.78
		$ 46,675.78
2013	Bank Charge	$ 400.00
	Transportation	$ 4,000.00
	Annual Meeting	$ 2,200.00
	Membership EDA	$ 5,300.00
	DPSP	$ 9,000.00
	WSIB	$ 2,500.00
	Payroll Remittance - CPP-EI	$ 11,100.00
	Benefit	$ 16,000.00
	Conference/Seminar	$ 4,000.00
		$ 54,500.00
2014	Bank Charge	$ 1,500.00
	Transportation	$ 5,000.00
	Annual Meeting	$ 3,000.00
	Membership EDA	$ 6,000.00
	DPSP	$ 9,405.00

	WSIB	$ 3,000.00
	Payroll Remittance - CPP-EI	$ 12,500.00
	Benefit	$ 18,000.00
	Conference/Seminar	$ 9,000.00
		$ 67,405.00

4.0 - VECC- 23

Reference: Exhibit 4, Tab 2, Schedule 1 / Schedule 2, pg. 3

a) At Exhibit 4, Tab 1, pg. 20 it appears to show that Embrun's billing costs have increased by $46,200 due to a move to monthly billing Please provide a breakdown of this and the other elements of customer billing in Account 5315 which shows the elements of the increase as between 2010 and 2014.

Response: Its CHEI's opinion that table 9 may have misunderstood the table 9 presented at page 20 (reproduced below).

Prior to 2011 CHEI billed its customer on a bi-monthly billing cycle and was being charged $46,200 by ORPC for these billing services. When CHEI opted to go on a monthly billing cycle, ORPC quoted $92,400 (or an increase of $46,200) for the service of printing and sending out monthly bills on CHEI's behalf)

In an effort to reduce costs, CHEI explored various options and opted to perform this service in-house instead. The cost of billing in-house served to **reduce** the potential cost of $92,400 down to $42,482.

Table 9 - 2013 Billing Cost Analysis

	ORPC			In-House		
Before 2011	**Bills**	**per bill**	**total**	**bills**	**per bill**	**total**
By-monthly billing	12000	$3.85	$46,200.00	12000	$0.85	$10,200.00
SubTotal	**12000**		**$46,200.00**			**$10,200.00**
Since 2011						
ORPC Monthly billing	24000	$3.85	$92,400.00	24000	$0.85	$20,400.00
Stamps						$17,000.00
Envelop						$1,600.00
Invoice						$1,000.00
Meter Rental						$575.00
Ink/Sealer						$100.00
NeoPost Maintenance						$1,807.00
Total	**24000**		**$92,400.00**			**$42,482.00**
%Change (year over year)						-54%

4.0 - VECC- 24

Reference: Exhibit 4, Tab 1, pg. 17

a) Please provide details as to the deferred profit share plan referred to at the above reference. Please indicate the current assets in the plan are in the plan, who benefits from the plan and under what conditions and how the plan is funded.

Response: This Deferred profit share plan is new as of 2011. The plan only benefits the 3 employees and is based a percentage of the annual salaries. The amount contributed into the plan by the employee is refunded upon termination of employment. The table below shows the contribution since the inception of the plan.

Further details can on the plan can be found at; http://www.inalco.com/english/individual/savings/retirement-savings/rrsp/rrsp.jsp#2

YEAR	CONTRIBUTION
2011	$ 5 566.00
2012	$ 13 981.00
TOTAL	$ 19 547.00

b) What is the total amount to be recovered for the deferred profit plan in 2014 OM&A.

Response: No amounts are recovered unless an employee of the cooperative is terminated or leaves. The projected expenses for 2013 and 2014 are $9,000 and $9,405 respectively.

4.0 - VECC- 25

Reference: Exhibit 4, Tab 2, Schedule 4

a) Please provide the productivity offset and stretch factors that were used by the Board for Embrun during the previous IRM period.

Response: As per the decision and order EB-2012-0117 issued on April 4th 2013, the stretch factor was 0.4%.

4.0 - VECC- 26

Reference: Exhibit 4, Tab 1

a) Please provide the training and staff development budgets in each year 2009 through 2013.

Response;

YEAR	BUDGET
2009	$ 2,500.00
2010	$ 2,000.00
2011	$ 2,000.00
2012	$ 2,000.00
2013	$ 2,000.00

4.0-VECC – 27

Reference: Exhibit 4, Tab 6

a) As a cooperative is Embrun entitle to any special (i.e. different from corporate) tax treatment? If so please explain.

Response; None except of the patronage returns which are tax deductible

4.0-VECC – 28

Reference: Exhibit 4, Tab 6

a) If available, please provide the 2013 OM&A spending to-date (ending August) in detailed format showing in three columns: the 2013 forecast; year-to-date; expected to-year end.

b)

2013 OM&A SPENDING TO DATE

ACCOUNT #	FORECAST	ACTUAL	EXPECTED YEAR END
5012	$ 1,600.00	$ 734.38	$ 1,500.00
5035	$ 3,000.00	$ 620.00	$ 3,000.00
5065	$ 1,500.00	$ 613.60	$ 1,300.00
5075	$ 6,000.00	$ 8,759.00	$ 9,500.00
5085	$ 3,450.00	$ 4,472.00	$ 5,000.00
5110	$ 8,600.00	$ 4,315.00	$ 8,600.00
5114	$ 10,200.00	$ 2,037.00	$ 6,000.00
5120	$ 5,000.00	$ -	$ 4,000.00
5125	$ 5,000.00	$ 3,456.00	$ 5,000.00
5135	$ 6,000.00	$ 8,920.00	$ 9,500.00
5160	$ 5,000.00	$ 1,955.00	$ 4,000.00
5315	$ 125,857.00	$ 70,790.00	$125,000.00
5330	$ 3,200.00	$ 2,364.00	$ 3,200.00
5335	$ 5,000.00	$ -	$ 5,000.00

5410	$ 3,100.00	$ 2,365.00	$ 3,100.00
5605	$ 25,000.00	$ 14,531.00	$ 20,000.00
5610	$ 77,983.00	$ 54,681.00	$ 80,000.00
5615	$ 54,289.00	$ 46,604.00	$ 58,000.00
5620	$ 39,782.00	$ 29,586.00	$ 36,000.00
5630	$ 96,200.00	$ 62,400.00	$ 96,200.00
5635	$ 2,500.00	$ 1,500.00	$ 1,500.00
5640	$ 1,700.00	$ 2,956.00	$ 2,956.00
5655	$ 5,724.00	$ 5,100.00	$ 6,000.00
5670	$ 13,200.00	$ 8,800.00	$ 13,200.00
5681	$ 1,900.00	$ 1,862.00	$ 1,862.00
6205	$ 2,000.00	$ 2,000.00	$ 2,000.00
Total	$ 512,785.00	$ 341,420.98	$511,418.00

Exhibit 5 – Cost of Capital

5.0 - VECC- 29

Reference: Exhibit 5, Tab 1

a) Does Embrun hold any short-term bank debt (for example working capital reasons). If yes please describe the amount and terms.

Response: CHEI does not have any debt what so ever.

Exhibit 7 – Cost Allocation

7.0-VECC – 30

Reference: Exhibit 7, Tab 1, pages 5-6 (September 2013)

a) Please explain why service weighting factors are not applicable to the Streetlighting and USL classes.

Response: CHEI does not provide any services for StreetLights and USL classes therefore it would inappropriate allocated weighting factors to these 2 classes.

b) The Application states that the weighting factor for GS>50 is “2” as the time and cost of the installations require additional planning and preparation time due to the complexity of the metering equipment. The Application also states that, in the case of GS<50, requires slightly more planning and monitoring. Given this context, please explain why the GS<50 class has also been assigned a service weighting factor of “2” (per Cost Allocation model, Tab I5.2).

Response: Both general service classes tend to require a little more planning and preparation due to the metering equipment and often require more time and attention than the residential class.

7.0-VECC – 31

Reference: Cost Allocation Model, Sheet I7.1 (July 2013) Exhibit 7, Tab 1, page 6 (September Filing) Exhibit 2, Tab 2, Appendix B

a) Which categories of meters in Sheet I7.1 are “smart meters” per the recent smart meter program?

Response: All residential and GS<50 meters are smart meters. The entry should have been made under meter type “smart meter” and cost including installation shoudl have been 100.00. The corrected model is filed in conjunction with these replies.

b) Please show how the relative smart meter capital costs for the different customer classes as shown in Sheet I7.1 were derived from the smart meter costs by customer class reported in Exhibit 2.

Response: The corrected model is filed in conjunction with these replies.

7.0-VECC – 32

Reference: Cost Allocation Model, Sheets I3 and I7.2 (July 2013) Exhibit 7, Tab 1, page 6

a) Why are there no meter reading expenses in the Operating Expenses?

Response: Meter reading expenses are included in account 5315 Customer Billing. See response to VECC-19

7.0-VECC – 33

Reference: Cost Allocation Model, Sheet I8 (July 2013)

a) What is the basis for the load profiles used to create the demand allocators in Sheet I8?

Response: The profile used were the ones approved in the last Cost Allocation.

7.0-VECC – 34

Reference: Exhibit 6, Tab 1, Schedule 2, page 7 (September 2013 Filing) Exhibit 7, page 10 and Cost Allocation Model, Sheet I6.1 (from September 2013 Filing)

a) The revenue at existing rates set out in Exhibit 7 at page 10 ($839,063) does not agree with the value from Sheet I6.1 of the CA Model also provided in that Exhibit ($837,749). Furthermore, both of these values differ from the value use in Exhibit 6 ($781,348). Please indicate which value is correct and provide the necessary revisions to the evidence.

Response: As indicated in the technical conference, CHEI did not update the written evidence at Exhibit 7 and 8 to reflect the post filing revisions to the Cost Allocation Model. As indicated in the technical conference, CHEI committed to updating the evidence through its responses to IRs through an updated Revenue Requirement Workform. As such, a revised RRWF is being filed in conjunctions with these replies.

CHEI notes that the Cost Alloaction Model and the RRWF filed in September 2013 both show distribution revenue at current rates in the amount of $839,063.

7.0-VECC – 35

Reference: Exhibit 3, Tab 1, page 31 (September 2013 Filing) Exhibit 7, Tab 1, Cost Allocation Model Sheet I6.2 (September 2013)

a) The 2014 kWh by rate class used in the Cost Allocation Model do not reconcile with those set out in Exhibit 3 (e.g. the totals are 30,803 MWh and 30,899 MWh respectively). Please indicate which values are correct and provide the necessary revisions.

Response: As explained in the previous question, the difference is due to updates post filing.

The correct total load is $30,899 as per the revised Cost Allocation model filed on September 11, 2013

7.0-VECC – 36

Reference: Exhibit 6, Tab 1, Schedule 2 (September 2013 Filing) Exhibit 7, page 12 (September 2013 Filing)

Exhibit 8, page 11 - TESI-12 (September 2013 Filing)

a) The Total Proposed Service and Base Revenue Requirements differ across the three references as follows:

Response: Same as stated above. The proposed base revenue requirement is the one found in the RRWF filed on September 11, 2013 which is $838,797.

Please indicate which values are correct and provide the necessary revisions to the evidence filed.

Response: CHEI requires several additional days to update the entire application. CHEI commits to filing an updated version of the application by the 15th of October.

7.0-VECC – 37

Reference: Exhibit 7, Tab 1, page 12 (September 2013 Filing) Exhibit 7, Tab 1, pages 14-15 (July 2013 Filing)

Preamble: In its initial filing, Embrun had proposed to move the revenue to cost ratios for those classes outside the Board's policy range so as to be at the range limits and to adjust the ratios for the other classes so as to maintain revenue neutrality. However, in the July

2013 revision Embrun proposed to move all of the ratios to 100%. In the September 2013 filing Embrun appears to have reverted to its original proposal.

a) Please confirm what Embrun's proposal is with respect to the customer class revenue to cost ratios for 2014 and, if not already in evidence, provide a version of Appendix 2-P consistent with the proposed ratios and revenue requirement..

Response: It is still CHEI's proposal to move all of its ratios to 100%

b) If Embrun is now proposing to move all of the customer class revenue to cost ratios to 100% as of 2014, please indicate what improvements have been made to the cost allocation and, in particular regarding the customer class load profiles, that would justify this proposal?

Response: CHEI does not know of any improvement to the cost allocation other than the OEB dictating the utilities to use specific weighting factors. CHEI is of the opinion that using a 100% ratio means that each class is recovering its own cost through revenues collected. A100% revenue to cost ratio for each class serves to eliminate cross- subsidization between classes and seems, in CHEI's view, to be the ultimate goal of this exercise.

Exhibit 8 – Rate Design

8-Staff-30

Ref: E8.T1.S1 Fixed Variable Proportion – Revenues from Existing Fixed and Variable Charges

On Table 1 on page 6 under Exhibit 8, CHEI has used the bridge year volumes in the calculation of the projected revenue from existing variable charges. Please explain CHEI's rationale for using the bridge year as opposed to the test year (2014). If this is an error please re-file the table using the test year.

Response: The section of the application is entitled "Overview of Existing Rates" and therefore, the table served no other purpose than to show current rates currently in effect in 2013 applied to forecasted load for 2013. As the header in the table indicated, the table shows the projected revenues for the Bridge Year at current rates.

The test year projected revenues are current rates are presented at Exhibit 3, Tab 2 and page 34 of the application.

8-Staff-31

Ref: E8.T1.S5 Appendix 2-V – Reconciliation to Base Revenue Requirement

On page 13 under updated Exhibit 8, CHEI has provided that the proposed monthly service charges and volumetric rates are as follows:

Staff is unable to reconcile the proposed charges with CHEI's Appendix 2-V MS Excel version.

Please consider that in CHEI's evidence at E7.T1.S1 page 14 Table 6 Cost Allocation of Revenue Requirement, CHEI has indicated $30,281 in revenue offsets. Please explain how CHEI has arrived at the $869,078 in revenue on Appendix 2-V without including the $30,281 in revenue offsets. Please reconcile the difference and provide an updated Appendix 2-V.

Response: CHEI inadvertently used the Service Revenue Requirement instead of the Base Revenue Requirement in its Rate Design.

The updated table is presented below and updated Appendices is filed in conjunction with these replies.

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	1,998.00	1,998.00	1,998.00	21,296,520		$ 14.00	$ 0.0160		$ 675,538.06	$ 675,538		$ 675,538	$ -
GS < 50 kW	Customers	168.00	168.00	168.00	4,950,960		$ 22.50	$ 0.0081		$ 85,452.19	$ 85,452		$ 85,452	$ -
GS > 50 to 4,999 kW	Customers	11.00	11.00	11.00	4,187,781	12,372	$ 235.00		$ 1.9785	$ 55,498.12	$ 55,498		$ 55,498	$ -
Unmetered Scattered Load	Connections	20.00	20.00	20.00	89,554	-	$ 9.75	$ 0.0233		$ 4,429.01	$ 4,429			
StreetLights	Connections	425.00	425.00	425.00	374,609	1,001	$ 2.25		$ 6.3991	$ 17,880.49	$ 17,880		$ 17,880	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$ 838,797.87	$ 838,798	$ -	$ 838,798	$ -

8-Staff-32

Ref: E8.T5.S2 Table 7 Derivation of Proposed Low Voltage Charges – Low Voltage Charges

Table 7 on page 22 under Exhibit 8, CHEI has provided a table which indicates proposed LV charges for 2013 and not 2014.

c) Please confirm which year this is for.

Response: The heading should have stated 2014 instead of 2013 an updated table with corrected header is presented below

Low Voltage Charges

(not loss adjusted)

	2014 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	70.92%	39,717	21,296,520	$0.0019	kWh
General Service < 50 kW	14.43%	8,079	4,950,960	$0.0016	kWh
General Service > 50 to 4999 kW	13.54%	7,584	12,372	$0.6130	kW
Unmetered Scattered Load	0.26%	146	89,554	$0.0016	kWh
Street Lighting	0.85%	474	1,001	$0.4739	kW
MicroFit					
TOTAL	**100.00%**	**56,000**	**26,350,407**		

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**		**2013**			**2014**	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	19,627,850	$0.0014	$27,479	21,296,520	$0.0019	$40,463.39
General Service < 50 kW	kWh	4075	4750	4,804,973	$0.0013	$6,246	4,950,960	$0.0016	$7,921.54
General Service > 50 to 4999 kW	kW	4075	4750	12,607	$0.4778	$6,024	12,372	$0.6130	$7,584.04
Unmetered Scattered Load	kWh	4075	4750	91,612	$0.0013	$119	89,554	$0.0016	$143.29
Street Lighting	kW	4075	4750	1,000	$0.3694	$369	1,001	$0.4739	$474.37
MicroFit									
TOTAL		**0**	**0**	**24,538,041**		**$40,238**	**26,350,407**		**$56,586.62**

The figures in the "Non Uplifted Volumes" column should reflect the updated load forecast figures from CHEI's updated cost allocation model (worksheet I6.1 Revenue).

a) Please update Table 7 with the updated load forecast figures and provide an updated derivation of low voltage charges for 2014. Response: manu

Response: See table above

8-Staff-33

Ref: E8.T6.S2 Appendix 2-R Derivation of Proposed Loss Adjustment Factor – Supply Facilities Loss Factor

In Appendix 2-R, CHEI has inputted 1.034 for the Supply Facilities Loss Factor ("SFLF") for the years 2008 to 2010 and inputted 1.0443 for 2011 and 2012. Staff notes that the usual factor for an embedded distributor whose host is Hydro One is 1.034.

a) Please explain why CHEI has decided to use the 1.0443 for 2011 and 2012 when calculating the 5-year average for the SFLF?

Response: It's unclear to CHEI as to why the OEB would use outdated information. CHEI has used the actual loss factor from the Hydro One Powerbills. (see attached). As of 2011, Hydro One has been charging a loss factor of 1.0443 to its embedded distributors.

b) Please provide CHEI`s opinion on whether the SFLF value of 1.0443 inputted by CHEI should be used rather than the 1.034.

Response: it is board's practice and that utiliies should use the most up to date information available. In 2011, Hydro One updated its loss factor from 1.034 to 1.0443 and as such, the calculations should reflect the actual SFLF.

8-Staff-34

Ref: E8.T8.S1 Overview of Bill Impacts

CHEI has noted that "total bill impacts vary by customer class, ranging from a decrease of 18.10% for Unmetered Scattered Load, to an increase of 35.07% for Street Lighting." CHEI also noted that the General Service Greater Than 50 kW rate class is seeing the largest drop in rates at 45.03%.

a) Has CHEI considered alternatives to reduce the rate shock and volatility for the Unmetered Scattered Load and General Service Greater Than 50 kW rate classes? Response:

Response: In view of the changes to the Rate Design. The updated Bill Impacts per class are as such.

Res: -0.80%
GS<50: -7.24%
GS>50: -28.00%
USL: -23.39%
StreetLights:6.72%

The filing requirements state that a distributor must file a mitigation plan if total bill increases for any customer class exceed 10%. The mitigation plan must include the following information:…

CHEI attests that none of the bill increases exceed 10% and as such, CHEI does not need a rate mitigation plan.

b) Please provide a detailed rate mitigation plan for the Street Lighting rate class.

Please also provide an updated Appendix 2-W which reflects this rate mitigation plan.

Response: a rate mitigation plan is not warranted since none of the bill increases exceed 10%.

8-Staff-35

Ref: E8.T8.S1 Appendix 2-W – Bill Impacts

Staff has noticed a two inconsistencies with Appendix 2-W which was filed by CHEI on June 14, 2013 and the revised Exhibit 8 which was filed on September 12, 2013.

a) Staff notes that CHEI is proposing a monthly service charge of $12.00 for the Unmetered Scattered Load, however, in the revised Exhibit 8 the monthly service charge proposed is $9.75. Please confirm the correct proposed monthly service charge for the USL customer rate class.

Response: $9.75 as presented in the revised appendices filed in conjunction with these replies.

b) Staff also notes that the smart meter entity charge is a fixed monthly charge and should not be multiplied by volume. It appears that that the smart meter entity charge is being multiplied by volume for each customer rate class. Please confirm that it should not be, and if so re-file a corrected version of Appendix 2-W for the affected rate classes.

Response: The issue has been rectified in the revised appendices.

8.0-VECC – 38

Reference: Exhibit 8, Tab 1, page 9 (September 2013 Filing)

a) Please explain why a 50/50 fixed-variable split is considered by Embrun to be "fair and equitable".

Response: If a utility had a choice, they would select a 100% fixed and 0% variable to ensure revenue stability. If a customer had a choice, they would select a 100% variable so that they could have full control over the cost of their hydro bills. A 50/50 split ensures that both sides are getting their fair share.

8.0-VECC – 39

Reference: Exhibit 8, Tab 1, page 11 - Table TESI-12 (September 2013 Filing)

a) Please confirm that fixed variable split percentages calculated at existing rates used the 2014 load forecast quantities for each customer class. If not please revise the table to show the percentages calculated on this basis.

Response: CHEI confirms that the fixed variable split percentages calculated at existing rates did in fact use the 2014 load forecast quantities for each customer class therefore not change is required.

8.0-VECC – 40

Reference: Exhibit 8, Tab 5, pages 21-22 (September 2013 Filing)

a) Please provide a schedule setting out the calculation described on page 21 (first paragraph) that results in the proposed $56,434 in LV costs.

Response: The 2014 estimated $56,000 is a projection based on historical charges.

The table below shows historical LV charges paid over the last 2 years.

	2011	2012	2013 to date
4705 - LV Charges	$38,436	$40,483	
1150 – LV Variance Account	$11,124	$20,847	
Total LV paid	$57,325	$57,090	$58,211

The $56,000 is prorated based on the 2014 per class load forecast and then used to determine a LV Rate Rider.

8.0-VECC – 41

Reference: Exhibit 8, Tab 6, Appendix 2-R (September 2013 Filing)

a) Please explain the significant increase in annual loss factor experienced in 2011. If this is truly an anomaly, should it be excluded from the calculation?

Response: Although CHEI has attempted to investigate why line losses were unusually high in 2011, it has been unable to find a reason as to why line losses were so high. CHEI is commissioning Stantec to perform a line loss study.

8.0-VECC – 42

Reference: Exhibit 8, Tab 7, pg. 28, Table 9 / 2014 Appendices_20130614

a) Table 9 shows the total stranded meter for recovery at $42,924. The continuity schedule for 2012 shows account 1860 asset disposals of $79,072 and accumulated depreciation of $32,985 for a difference of 46,087. Please confirm the difference, $3,163 is the amount depreciated in 2013.

Response: The depreciation expense should have stated $36,147 (value in 2012) and not the depreciation expense of $32,985 (value of 2011). CHEI proposes to update the value as part of the Draft Rate Order. The impact on $189.00

8.0-VECC – 43

Reference: Exhibit 8, Tab 7, pg. 28, Table 9

a) Please provide a detailed calculation showing the derivation of the stranded meter weighting factor.

Response: CHEI used the Estimated SMFA Revenues from the Smart Meter model to determine the ratio for the Residential Class vs the GS<50 class

Residential	GS < 50 kW
$ 94,372.83	$ 8,512.47

b) Did Embrun maintain separate accounting records for meters in the two classes?

Response: CHEI did not maintain separate accounting records for meters in the two classes

c) Generally, stranded meters costs have been allocated on one of three methods: (1) actual class specific where available; (b) last Board approved cost allocation methodology; (c) smart meter cost allocation proxy. Please indicate what method is being used by Embrun.

Response: none of the above. See response to question a)

d) Please recalculate the stranded meter using the last Board approved cost allocation.

Response: CHEI has done so in the table below however CHEI maintains that using the last Board Approved Cost Allocation as a basis is using outdated parameters. Although CHEI admits that the use of the SMFA Revenues is not perfect either, they seem more be more representative of the ratios per class that will be affected by this rider.

Stranded Meter Rate Rider

Customer Class Name	Net Book Value	% share based on 2010 BA model	Annual $	Customer	Rate	per month
Residential	$39,919.32	93.00%	19959.66	1998	$ 9.99	$ 0.83
General Service < 50 kW	$3,004.68	7%	1502.34	168	$ 8.94	$ 0.75
enter classes						
	TOTAL	1.00				

Total for Recovery			**42,924**
Recovery Period (years)		**2**	
Annual Recovery			**21,462**

Note: Meter Capital from Sheet 17.1 of the 2010 Board approved CA model

Total Meter Cost: $82,100

GS<50 Meter Cost: $6,000

Residential Meter Cost: $76,100

Exhibit 9 – Deferral and Variance Accounts

9-Staff-36

Ref: E9.T1.S4 Deferral and Variance Account Balances – Calculation of Rate Rider

On page 16 and 17 of Exhibit 9, CHEI is proposing to dispose of the balances in Table 1 (on page 14 and 15) over two years. Staff notes that CHEI did not provide the calculations of the DVA rate riders in E9.T1.S4. Please provide the missing DVA rate rider calculations in E9.T1.S4.

Response: The Rate Rider calculations are presented at the next page. Please note that CHEI has used V2.2 of the EDDVAR model. This was done in order to calculated the rate rider for account 1576. The use of V2.2 of the EDDVAR model, along with the removal of account 1592 resulted in rate riders which differ from the ones presented in the May application.

The revised evidence is being filed in conjunction with these replies.

Please indicate the Rate Rider Recovery Period (in years) | **2**

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	19,634,780	-$ 91,466	- 0.0023	$/kWh
General Service < 50 kW	kWh	4,742,923	-$ 21,618	- 0.0023	$/kWh
General Service > 50 to 4999 kW	kW	12,486	-$ 19,027	- 0.7619	$/kW
Unmetered Scattered Load	kWh	89,208	-$ 417	- 0.0023	$/kWh
Street Lighting	kW	1,003	-$ 1,655	- 0.8249	$/kW
		-	$ -	-	
Total			**-$ 134,182**		

Rate Rider Calculation for RSVA - Power - Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	Non-RPP kW / kWh / # of Customers	Balance of RSVA - Power - Global Adjustment	Rate Rider for RSVA - Power - Global Adjustment	
Residential	kWh	911,692	-$ 1,260	- 0.0007	$/kWh
General Service < 50 kW	kWh	312,122	-$ 431	- 0.0007	$/kWh
General Service > 50 to 4999 kW	kW	12,486	-$ 5,931	- 0.2375	$/kW
Unmetered Scattered Load	kWh	14,167	-$ 20	- 0.0007	$/kWh
Street Lighting	kW	1,003	-$ 491	- 0.2449	$/kW
Total			**-$ 8,133**		

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) | **2**

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576	
Residential	kWh	19,634,780	$ 29,454	0.0008	$/kWh
General Service < 50 kW	kWh	4,742,923	$ 2,586	0.0003	$/kWh
General Service > 50 to 4999 kW	kW	12,486	$ 181	0.0073	$/kW
Unmetered Scattered Load	kWh	89,208	$ 313	0.0018	$/kWh
Street Lighting	kW	1,003	$ 6,738	3.3587	$/kW
Total			**$ 39,272**		

9-Staff-37

Ref: E9.T1.S2 Account 1508, Other Regulatory Assets – Sub account OEB Cost Assessments & Account 1508, Other Regulatory Assets – Sub account Pension Contributions

CHEI provided Table 1 on page 14 of Exhibit 9 requesting the disposition of the December 31, 2012 balances in Account 1508, Sub Account OEB Cost Assessments and Account 1508, Sub Account Pension Contributions.

Although the amounts are not material, Staff notes that CHEI had the opportunity in its previous COS rates application to request the disposition of the two sub accounts but did not follow the December 2005 APH FAQ # 13, which indicates "these recordings are authorized to April 30, 2006 since effective on May 1, 2006 cost assessments and cash pension contributions amounts are included in the distribution rates of LDCs for the 2006/07 rate year."

Staff notes the Board findings in the EB 2011-0293 Board Decision, denying Atikokan Hydro's request for recovery of OMERS contributions for the period 2006 to 2011 and OEB cost assessments for the period 2006 to 2009 as being out of period.

Please explain why the Board should approve CHEI's request for disposition of the balances in Account 1508, Sub Account OEB Cost Assessments and Account 1508, Sub Account Pension Contributions in this rate proceeding. Response: group 2 are disposed as part of Cost of Service. This is the next available cost after 2011

Response: CHEI notes that it did seek and was approved disposition of the amount of 5251 in its 2010 cost of service application. The remnants of $5,65 represent minor transactions which occurred in early 2010 after disposal through 2010 Board Approved rates.

9-Staff-38

Ref: E9.T1.S1 page 5 and 12 Account 1580, RSVA-WMS and Account 1592, PILS & Tax Variances for 2006 and Subsequent Years, Sub Account HST/OVAT Input Tax Credits

CHEI is requesting the disposition of Accounts 1580 and Account 1592, Sub account HST/OVAT ITCs.

Staff, however noted the differences in the requested amounts for disposition in Table 1 and E9T1/S1 for these two accounts.

Response: CHEI had conferred with its auditors and it seems as if the balance in 1592, where represented future income taxes, should have been applied to account 6115 instead. CHEI proposes to remove these balances from the deferral and variance accounts disposition.

Please state what are the correct amounts requested for disposition for Accounts 1580 and 1592, Sub account HST/OVAT ITCs and make all the necessary adjustments required, if any, including Table 1 in E9/T1/S2, DVA rate riders calculations, DVA Work Form, etc.

Response: The amount sought for disposition for account 1580 is $23,665

9-Staff-39

Ref: E9.T1.S6 page 18 Account 1588, RSVA – Power

CHEI provided the 2009 to 2012 Audited Financial Statements as well as Table 2: Energy Sales and Cost of Power Expenses.

Staff noted that CHEI did not follow the filing requirements to provide the breakdown of the total energy sales and the total cost of power expenses for 2009 to 2012 as reported in the Audited Financial Statements. In addition, Staff noted that CHEI did not provide the reconciliation between the energy sales and cost of power in Table 2 and the 2009-2012 Audited Financial Statements as required by the COS filing requirements.

a) Please provide the reconciliation between the total energy sales and cost of power in Table 2 and the total energy sales and cost of power in the 2009 to 2012 Audited Financial Statements.

Response: CHEI does not state its cost of power in its audited financial statements. Instead, the power supply expense is netted against the service revenues. The break down used by BDO to determine the power supply expenses is presented at the next page. The first two pages show years 2006-2010 and the last 2 pages show comparative from 2011to 2012.

b) Is CHEI showing a profit or loss on commodity? If yes, please explain why. Response:

Response: CHEI does not record any profit or loss on commodity.

Coopérative Hydro Embrun inc./Embrun Hydro Cooperative Inc.

Year End: December 31, 2010

Revenue

Account	Rep 10	Rep 09	%Chg	Rep 08	%Chg	Rep 07	%Chg	Rep 06	%Chg
408000 RESIDENTIAL MNTHLY SE	**(274,163.87)**	(247,549.47)	**11**	(240,519.73)	**3**	(223,744.66)	**7**	(206,573.85)	**8**
408001 RESIDENTIAL DIST VOL R	**(226,328.76)**	(182,781.39)	**24**	(178,760.00)	**2**	(166,004.20)	**8**	(146,152.41)	**14**
408002 SSS ADMINISTRATION CH	**(4,829.87)**	(4,774.49)	**1**	(4,663.05)	**2**	(4,657.47)	**0**	(4,733.30)	**(2)**
408009 DIST-SERV.REV. PILS REC	**0.00**	0.00	**0**	0.00	**0**	(29,747.98)	**(100)**	8,088.34	**(468)**
408010 GS<50 MONTHLY SERVIC	**(35,849.42)**	(29,127.90)	**23**	(30,865.30)	**(6)**	(29,045.64)	**6**	(28,074.86)	**3**
408011 BELOW 50 DIST VOL RATI	**(71,898.09)**	(62,415.74)	**15**	(63,865.20)	**(2)**	(61,805.80)	**3**	(54,526.94)	**13**
408012 <50 -SSS ADMINISTRATIO	**(475.10)**	(465.39)	**2**	(515.36)	**(10)**	(516.65)	**0**	(531.74)	**(3)**
408020 GS>50 MONTHLY SERVIC	**(25,168.46)**	(33,796.14)	**(26)**	(34,608.36)	**(2)**	(33,886.84)	**2**	(34,376.71)	**(1)**
408021 GS>50 DIST VOL RATE - K	**(30,630.10)**	(32,962.01)	**(7)**	(33,910.62)	**(3)**	(35,017.75)	**(3)**	(32,282.70)	**8**
408022 >50KW - SSS ADMIN CHAI	**(25.85)**	(35.07)	**(26)**	(36.14)	**(3)**	(36.13)	**0**	(36.91)	**(2)**
408023 INTERVAL - SERVICE CHA	**(6,678.33)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
408024 INTERVAL - DIST VOL RAT	**(14,992.94)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
408025 INTERVAL - SSS ADMIN C	**(7.09)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
408040 STREET LIGHTING MNTHI	**(6,537.28)**	(4,086.28)	**60**	(4,053.72)	**1**	(3,792.44)	**7**	(3,615.39)	**5**
408041 STREET LIGHTING DIST V	**(5,416.28)**	(3,419.36)	**58**	(3,564.95)	**(4)**	(3,313.52)	**8**	(2,945.69)	**12**
408042 STREETLGHTS - SSS ADM	**(3.00)**	(3.00)	**0**	(3.00)	**0**	(3.00)	**0**	(3.00)	**0**
408050 UNMETERED-SSS ADMIN	**(54.00)**	(54.00)	**0**	0.00	**0**	0.00	**0**	0.00	**0**
408060 UNMETERED MTHLY SER	**(6,582.36)**	(1,755.41)	**275**	0.00	**0**	0.00	**0**	0.00	**0**
408061 UNMETERED VOLUMETRI	**(1,006.48)**	(1,201.98)	**(16)**	0.00	**0**	0.00	**0**	0.00	**0**
408070 S/C MICROFIT	**(27.83)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
500.02 Revenus de service	**(710,675.11)**	**(604,427.63)**	**18**	**(595,365.43)**	**2**	**(591,572.08)**	**1**	**(505,765.16)**	**17**
470501 MICRO FIT GENERATION	**99.42**	0.00	**0**	0.00	**0**	800.00	**(100)**	0.00	**0**
470502 COMMODITY PURCHASE	**1,065,230.29**	982,693.68	**8**	1,460,624.20	**(33)**	1,620,035.54	**(10)**	1,434,888.61	**13**
470600 PROVINCIAL BENEFITS	**893,984.31**	218,283.29	**310**	0.00	**0**	0.00	**0**	0.00	**0**
470800 WHOSALE MARKET CHAF	**157,799.29**	164,275.10	**(4)**	181,770.49	**(10)**	179,904.87	**1**	173,735.65	**4**
471400 NETWORK TRANS. CHAR	**147,693.15**	133,574.72	**11**	136,421.29	**(2)**	160,187.91	**(15)**	153,534.01	**4**
471600 CONNECTION NETWORK	**131,243.14**	123,851.35	**6**	125,546.19	**(1)**	136,513.22	**(8)**	130,527.01	**5**
475000 Low Voltage Charge	**32,374.57**	27,912.26	**16**	36,609.46	**(24)**	37,456.56	**(2)**	20,284.64	**85**
500.12 Power Purchased	**2,428,424.17**	**1,650,590.40**	**47**	**1,940,971.63**	**(15)**	**2,134,898.10**	**(9)**	**1,912,969.92**	**12**
400680 PROV. BENEFIT SPOT CU	**(152,781.84)**	(63,185.20)	**142**	0.00	**0**	0.00	**0**	0.00	**0**
400685 ELECTRICITY CHARGE RE	**(1,208,067.11)**	(480,824.91)	**151**	0.00	**0**	0.00	**0**	0.00	**0**
400686 ELECTRICITY CHARGE BE	**(341,652.94)**	(322,593.05)	**6**	0.00	**0**	0.00	**0**	0.00	**0**
400696 ELECTRICITY CHARGE UI	**(5,966.62)**	(5,617.80)	**6**	0.00	**0**	0.00	**0**	0.00	**0**
400697 ELECTRICITY CHARGE >5	**0.00**	(194,096.54)	**(100)**	(239,247.42)	**(19)**	(231,316.54)	**3**	(228,617.97)	**1**
400699 ELECTRICITY CHARGE RE	**0.00**	0.00	**0**	(1,054,608.28)	**(100)**	(1,245,095.72)	**(15)**	(1,112,741.94)	**12**
401500 INTERVAL METERED-SSS	**(47,656.84)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
402500 STREET LIGHTING ENERC	**(12,402.91)**	(1,460.63)	**749**	0.00	**0**	0.00	**0**	0.00	**0**
402502 STREETLGHTS - SSS ENE	**0.00**	(21,770.39)	**(100)**	(24,834.00)	**(12)**	(24,933.31)	**0**	(24,483.88)	**2**
403514 >50KW - SSS - ENERGY C	**(114,738.06)**	(43,908.54)	**161**	(29,686.26)	**48**	(28,388.26)	**5**	(28,031.08)	**1**
405520 RETAILER COP UNIVERSA	**(6,878.98)**	(13,627.37)	**(50)**	(20,146.93)	**(32)**	(15,257.24)	**32**	(3,086.99)	**394**
405530 RETAILER COP - DIRECT I	**(11,305.25)**	(10,053.06)	**12**	(18,866.51)	**(47)**	(18,516.37)	**2**	(14,765.11)	**25**
405540 RETAILER CANADA ENER	**(727.83)**	(301.48)	**141**	(516.72)	**(42)**	(205.12)	**152**	0.00	**0**
405550 RETAILER SUPERIOR ENI	**(300.73)**	(335.48)	**(10)**	(264.78)	**27**	0.00	**0**	0.00	**0**
405560 RETAILER COP - OIS	**(53,999.56)**	(43,010.17)	**26**	(72,456.30)	**(41)**	(56,322.98)	**29**	(23,161.64)	**143**
405630 RETAILER SUMMIT	**(2,835.35)**	(192.35)	**1,374**	0.00	**0**	0.00	**0**	0.00	**0**
406200 RES WHOLESALE MARTK	**(93,947.06)**	(99,603.41)	**(6)**	(116,944.36)	**(15)**	(116,137.27)	**1**	(111,365.53)	**4**
406201 <50KW WHOLESALE MAR	**(32,585.79)**	(33,472.84)	**(3)**	(33,374.43)	**0**	(33,862.52)	**(1)**	(32,361.30)	**5**
406202 >50KW WHOLESALE MAR	**(19,933.16)**	(28,179.96)	**(29)**	(28,893.25)	**(2)**	(27,404.38)	**5**	(27,594.48)	**(1)**

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Prepared by	Detail Rev	Gen Rev
MAR 03/10/2011	AB 03/17/2011	
Concur Rev	**4th Level Rev**	**Tax Rev**

REV

Coopérative Hydro Embrun inc./Embrun Hydro Cooperative Inc.
Year End: December 31, 2010
Revenue

Account	Rep 10	Rep 09	%Chg	Rep 08	%Chg	Rep 07	%Chg	Rep 06	%Chg
406203 INTERVAL WHOLESALE M	**(8,237.92)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
406204 STLIGHT WHOLESALE MA	**(2,476.60)**	(2,388.77)	**4**	(2,558.48)	**(7)**	(2,500.70)	**2**	(2,414.34)	**4**
406206 WHOLESALE MARTKET U	**(618.76)**	(630.12)	**(2)**	0.00	**0**	0.00	**0**	0.00	**0**
406600 TRANS. NETWORK SERV	**(99,749.56)**	(85,023.77)	**17**	(86,197.39)	**(1)**	(101,202.27)	**(15)**	(95,479.17)	**6**
406601 <50KW NETWORK SERVIC	**(23,741.99)**	(24,181.32)	**(2)**	(24,944.02)	**(3)**	(28,400.85)	**(12)**	(27,141.89)	**5**
406602 >50KW NETWORK SERVIC	**(15,420.08)**	(22,480.80)	**(31)**	(23,776.83)	**(5)**	(28,915.15)	**(18)**	(29,291.00)	**(1)**
406603 INTERVAL NETWORK SER	**(6,896.94)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
406604 STLIGHT NETWORK SERV	**(1,433.80)**	(1,432.58)	**0**	(1,503.06)	**(5)**	(1,669.64)	**(10)**	(1,621.95)	**3**
406606 TRANS. NETWORK UNME	**(450.78)**	(456.25)	**(1)**	0.00	**0**	0.00	**0**	0.00	**0**
406800 TRANS. CONNECTION SE	**(88,442.87)**	(77,661.94)	**14**	(78,768.68)	**(1)**	(86,124.37)	**(9)**	(80,952.39)	**6**
406801 <50KW LINE&TRANS CON	**(21,274.80)**	(23,187.60)	**(8)**	(23,546.18)	**(2)**	(24,577.54)	**(4)**	(23,487.79)	**5**
406802 >50KW LINE&TRAN CONN	**(13,748.78)**	(21,184.26)	**(35)**	(21,806.97)	**(3)**	(24,368.94)	**(11)**	(24,685.63)	**(1)**
406803 INTERVAL LINE&TRAN CC	**(6,070.20)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
406804 STLIGHT LINE&TRANS CC	**(1,303.48)**	(1,381.16)	**(6)**	(1,424.68)	**(3)**	(1,442.37)	**(1)**	(1,401.20)	**3**
406806 TRANS. CONNECTION UN	**(403.01)**	(436.38)	**(8)**	0.00	**0**	0.00	**0**	0.00	**0**
407500 LV CHARGES BILLED - CU	**0.00**	10,240.25	**(100)**	(35,068.82)	**(129)**	(37,456.87)	**(6)**	(20,284.64)	**85**
407501 LV CHARGES BILLED-RES	**(19,734.71)**	(23,939.01)	**(18)**	(1,540.66)	**1,454**	0.00	**0**	0.00	**0**
407502 LV CHARGES BILLED-BEL	**(5,809.26)**	(5,421.90)	**7**	0.00	**0**	0.00	**0**	0.00	**0**
407503 LV CHARGES BILLED-OVE	**(4,575.44)**	(8,266.82)	**(45)**	0.00	**0**	0.00	**0**	0.00	**0**
407504 LV CHARGES BILLED-UNM	**(110.56)**	(101.74)	**9**	0.00	**0**	0.00	**0**	0.00	**0**
407505 LV CHARGES BILLED-STR	**(386.12)**	(423.54)	**(9)**	0.00	**0**	0.00	**0**	0.00	**0**
407506 INTERVAL - LV CHARGE	**(1,758.48)**	0.00	**0**	0.00	**0**	0.00	**0**	0.00	**0**
500.14 Revenu à remettre Hydro	**(2,428,424.17)**	**(1,650,590.89)**	**47**	**(1,940,975.01)**	**(15)**	**(2,134,098.41)**	**(9)**	**(1,912,969.92)**	**12**
	(710,675.11)	**(604,428.12)**	**18**	**(595,368.81)**	**2**	**(590,772.39)**	**1**	**(505,765.16)**	**17**

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Prepared by	Detail Rev	Gen Rev
MAR 03/10/2011	AB 03/17/2011	
Concur Rev	**4th Level Rev**	**Tax Rev**

Coopérative Hydro Embrun inc./Embrun Hydro Cooperative Inc.

Year End: December-31-12

Revenue

Account	Prelim	Adj's	Rep	Rep 12/11	Amount Chg	%Chg
400681 0NTARIO CLEAN ENERGY CUSTOMER CREDIT	29,443.84	-29,443.84	0.00	0.00	**0.00**	**0**
408000 RESIDENTIAL MNTHLY SERVICE CHG	-266,926.42	-24,379.12	-291,305.54	-288,515.16	**-2,790.38**	**1**
408001 RESIDENTIAL DIST VOL RATE-KWH	-223,239.77	-25,440.88	-248,680.65	-249,475.02	**794.37**	**0**
408002 SSS ADMINISTRATION CHARGE	-4,676.18	-428.90	-5,105.08	-4,979.00	**-126.08**	**3**
408009 DIST-SERV.REV. PILS RECOVERY	-85,688.03	0.00	-85,688.03	0.00	**-85,688.03**	**0**
408010 GS<50 MONTHLY SERVICE CHARGE	-34,899.43	-3,156.77	-38,056.20	-38,458.68	**402.48**	**-1**
408011 BELOW 50 DIST VOL RATE	-71,739.85	-7,249.33	-78,989.18	-77,579.57	**-1,409.61**	**2**
408012 <50 -SSS ADMINISTRATION CHARGE	-393.15	-35.49	-428.64	-456.83	**28.19**	**-6**
408020 GS>50 MONTHLY SERVICE CHARGE	-21,412.64	-1,952.80	-23,365.44	-23,215.36	**-150.08**	**1**
408021 GS>50 DIST VOL RATE - KWH	-36,204.29	-3,168.14	-39,372.43	-33,430.33	**-5,942.10**	**18**
408022 >50KW - SSS ADMIN CHARGE	-16.50	-1.50	-18.00	-22.50	**4.50**	**-20**
408023 INTERVAL - SERVICE CHARGE	-8,029.74	-732.30	-8,762.04	-8,705.76	**-56.28**	**1**
408024 INTERVAL - DIST VOL RATE - KWH	-18,956.13	-1,501.47	-20,457.60	-19,711.93	**-745.67**	**4**
408025 INTERVAL - SSS ADMIN CHARGE	-8.25	-0.75	-9.00	-9.00	**0.00**	**0**
408040 STREET LIGHTING MNTHLY S/C	-7,137.05	-650.31	-7,787.36	-7,754.64	**-32.72**	**0**
408041 STREET LIGHTING DIST VOL RATE	-5,942.53	-541.95	-6,484.48	-6,442.76	**-41.72**	**1**
408042 STREETLGHTS - SSS ADMIN CHG	0.00	0.00	0.00	-2.00	**2.00**	**-100**
408050 UNMETERED-SSS ADMIN CHG	-33.75	-3.25	-37.00	-49.50	**12.50**	**-25**
408060 UNMETERED MTHLY SERVICE CHARGE	-8,295.78	-756.58	-9,052.36	-8,993.84	**-58.52**	**1**
408061 UNMETERED VOLUMETRIC CHARGE	-847.26	-77.30	-924.56	-915.23	**-9.33**	**1**
408070 S/C MICROFIT	-236.95	0.00	-236.95	-99.75	**-137.20**	**138**
408072 RESIDENTIAL-rate rider LRAM	-4,327.87	0.00	-4,327.87	0.00	**-4,327.87**	**0**
408073 OVER 50 - rate rider LRAM	-122.36	0.00	-122.36	0.00	**-122.36**	**0**
408074 INTERVAL- rate rider LRAM	-80.13	0.00	-80.13	0.00	**-80.13**	**0**
423510 Residential - Rate Rider Rec Late Payment Ligitati	-1,340.75	0.00	-1,340.75	-1,870.94	**530.19**	**-28**
423520 <50 kW- Rate Rider Rec Late Payment Ligitation	-276.30	0.00	-276.30	-390.36	**114.06**	**-29**
423530 >50kW-Rate Rider Rec Late Payment Ligitation	-132.00	0.00	-132.00	-184.80	**52.80**	**-29**
423540 USL - Rate Rider Rec Late Payment Ligitation	-8.55	0.00	-8.55	-11.97	**3.42**	**-29**
423550 STREET LIGHTING - Rate Rider Rec Late Payment Ligi	-24.54	0.00	-24.54	-20.46	**-4.08**	**20**
423560 Interval - Rate Rider Rec Late Payment Ligitation	-49.50	0.00	-49.50	-69.30	**19.80**	**-29**
621500 LATE PAUMENT PENALTIES	1,723.96	0.00	1,723.96	2,547.83	**-823.87**	**-32**
500.02 Revenus de service	**-769,877.90**	**-99,520.68**	**-869,398.58**	**-768,816.86**	**-100,581.72**	**13**
408201 RETAIL SER REV - SERVICE AGREE	-200.00	0.00	-200.00	-200.00	**0.00**	**0**
408204 BILL READY CHARGE	-402.60	0.00	-402.60	-492.30	**89.70**	**-18**
500.02. 1 OTH - Revenus de services	**-602.60**	**0.00**	**-602.60**	**-692.30**	**89.70**	**-13**
422500 LATE PAYMENT CHARGES - RESIDEN	-4,549.51	0.00	-4,549.51	-5,968.81	**1,419.30**	**-24**
422501 LATE PAYMENT CHARGE - COMM	-658.49	0.00	-658.49	-1,140.29	**481.80**	**-42**
500.02. 2 OTH - Frais de retard	**-5,208.00**	**0.00**	**-5,208.00**	**-7,109.10**	**1,901.10**	**-27**
437503 EXPENSE BUSINEES LIGHTING	78,371.25	0.00	78,371.25	0.00	**78,371.25**	**0**
437504 REVENU BUSINEES LIGHTING	-78,371.25	0.00	-78,371.25	0.00	**-78,371.25**	**0**
500.08 Autres revenus	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0**
400610 ON PEAK RESIDENTIAL	-317,060.21	-38,319.33	-355,379.54	0.00	**-355,379.54**	**0**
400611 OFF PEAK RESIDENTIAL	-654,703.02	-89,337.22	-744,040.24	0.00	**-744,040.24**	**0**
400612 MID PEAK RESIDENTIAL	-258,797.93	-28,496.89	-287,294.82	0.00	**-287,294.82**	**0**
400680 PROV. BENEFIT SPOT CUST	-202,637.90	-23,087.30	-225,725.20	-222,876.48	**-2,848.72**	**1**
400685 ELECTRICITY CHARGE RES	-75,306.76	6,226.40	-69,080.36	-1,315,300.68	**1,246,220.32**	**-95**
400686 ELECTRICITY CHARGE BELOW 50KW	-39,040.42	0.00	-39,040.42	-361,132.99	**322,092.57**	**-89**
400696 ELECTRICITY CHARGE UNMETERED	-5,457.87	-500.45	-5,958.32	-6,099.71	**141.39**	**-2**
401010 ON PEAK LESS THAN 50	-98,016.53	-8,808.18	-106,824.71	0.00	**-106,824.71**	**0**
401011 OFF PEAK LESS THAN 50	-137,658.95	-17,293.68	-154,952.63	0.00	**-154,952.63**	**0**
401012 MID PEAK LESS THAN 50	-75,544.28	-7,705.36	-83,249.64	0.00	**-83,249.64**	**0**
401500 INTERVAL METERED-SSS ENERGY CH	-34,623.97	-3,670.91	-38,294.88	-48,532.39	**10,237.51**	**-21**

Coopérative Hydro Embrun inc./Embrun Hydro Cooperative Inc.

Year End: December-31-12

Revenue

Account	Prelim	Adj's	Rep	Rep 12/11	Amount Chg	%Chg
402500 STREET LIGHTING ENERGY SPOT PRICE	0.00	0.00	0.00	-6,366.72	**6,366.72**	**-100**
403514 >50KW - SSS - ENERGY CHARGE	-45,069.65	-4,702.06	-49,771.71	-79,644.90	**29,873.19**	**-38**
405530 RETAILER COP - DIRECT ENG	-1,236.11	-56.61	-1,292.72	-4,313.33	**3,020.61**	**-70**
405535 RETAILER BRUCE POWER	-1,584.79	-288.60	-1,873.39	0.00	**-1,873.39**	**0**
405540 RETAILER CANADA ENERGY	-674.78	-53.93	-728.71	-1,263.61	**534.90**	**-42**
405550 RETAILER SUPERIOR ENERGY	-250.75	-15.74	-266.49	-282.38	**15.89**	**-6**
405560 RETAILER COP - OIS	-51,683.21	-6,191.47	-57,874.68	-54,477.55	**-3,397.13**	**6**
405630 RETAILER SUMMIT	-2,286.04	-242.37	-2,528.41	-2,793.12	**264.71**	**-9**
470501 MICRO FIT GENERATION	30,110.79	0.00	30,110.79	6,026.74	**24,084.05**	**400**
470502 COMMODITY PURCHASE HYDRO ONE	600,447.16	95,541.42	695,988.58	858,276.73	**-162,288.15**	**-19**
470600 PROVINCIAL BENEFITS	1,371,075.22	127,002.28	1,498,077.50	1,238,780.39	**259,297.11**	**21**
500.12 Power Purchased	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0**
406200 RES WHOLESALE MARTKET SERV REV	-113,440.69	-13,350.90	-126,791.59	-112,857.92	**-13,933.67**	**12**
406201 <50KW WHOLESALE MARKET SRV REV	-29,065.39	-2,893.03	-31,958.42	-32,136.41	**177.99**	**-1**
406202 >50KW WHOLESALE MARKET SRV REV	-17,426.83	-1,812.11	-19,238.94	-17,890.72	**-1,348.22**	**8**
406203 INTERVAL WHOLESALE MARKT SV RV	-9,265.21	-911.96	-10,177.17	-9,982.00	**-195.17**	**2**
406204 STLIGHT WHOLESALE MARKET SV RV	-2,171.05	-258.96	-2,430.01	-2,456.86	**26.85**	**-1**
406206 WHOLESALE MARTKET UNMETERED	-551.50	-49.58	-601.08	-611.15	**10.07**	**-2**
470800 WHOSALE MARKET CHARGE	171,920.67	19,276.54	191,197.21	175,935.06	**15,262.15**	**9**
500.13 Power Purchased Wholesale	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0**
406600 TRANS. NETWORK SERV RATE-REV	-99,544.97	-12,068.35	-111,613.32	-115,582.65	**3,969.33**	**-3**
406601 <50KW NETWORK SERVICE RATE	-25,529.63	-2,571.63	-28,101.26	-26,103.65	**-1,997.61**	**8**
406602 >50KW NETWORK SERVICE REV	-17,709.03	-1,568.32	-19,277.35	-15,682.85	**-3,594.50**	**23**
406603 INTERVAL NETWORK SERVICE RATE	-9,391.97	-743.27	-10,135.24	-9,309.33	**-825.91**	**9**
406604 STLIGHT NETWORK SERVICE REV	-1,549.25	-141.15	-1,690.40	-1,595.80	**-94.60**	**6**
406606 TRANS. NETWORK UNMETERED	-485.10	-44.10	-529.20	-499.01	**-30.19**	**6**
471400 NETWORK TRANS. CHARGE	154,209.95	17,136.82	171,346.77	168,773.29	**2,573.48**	**2**
500.15 Power purchased Network	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0**
407501 LV CHARGES BILLED-RESIDENTIAL	-24,685.39	-2,804.50	-27,489.89	-26,207.81	**-1,282.08**	**5**
407502 LV CHARGES BILLED-BELOW 50KW	-5,602.19	-564.33	-6,166.52	-6,075.56	**-90.96**	**1**
407503 LV CHARGES BILLED-OVER 50KW	-3,838.26	-334.68	-4,172.94	-3,565.09	**-607.85**	**17**
407504 LV CHARGES BILLED-UNMETERED	-106.26	-9.66	-115.92	-115.51	**-0.41**	**0**
407505 LV CHARGES BILLED-STREET LIGHT	-339.68	-30.88	-370.56	-370.56	**0.00**	**0**
407506 INTERVAL - LV CHARGE	-2,008.36	-158.62	-2,166.98	-2,101.93	**-65.05**	**3**
475000 Low Voltage Charge	36,580.14	3,902.67	40,482.81	38,436.46	**2,046.35**	**5**
500.17 Power purchased low voltage	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0**
408202 FIXED MTHLY CHARGE	-2,340.00	0.00	-2,340.00	-2,200.00	**-140.00**	**6**
408203 VARIABLE MTHLY CHARGE	-671.50	0.00	-671.50	-820.50	**149.00**	**-18**
408401 STR REVENUE-REQUEST FEE	-7.50	0.00	-7.50	-11.50	**4.00**	**-35**
500.17. 1 OTH - Power purchased low voltage	**-3,019.00**	**0.00**	**-3,019.00**	**-3,032.00**	**13.00**	**0**
406800 TRANS. CONNECTION SERVICE-REV	-82,061.73	-9,776.65	-91,838.38	-96,568.63	**4,730.25**	**-5**
406801 <50KW LINE&TRANS CONNECTION RV	-19,605.20	-1,974.63	-21,579.83	-20,907.88	**-671.95**	**3**
406802 >50KW LINE&TRAN CONNECT REV	-13,670.34	-1,191.44	-14,861.78	-12,503.42	**-2,358.36**	**19**
406803 INTERVAL LINE&TRAN CONNECT RV	-7,149.79	-564.66	-7,714.45	-7,384.94	**-329.51**	**4**
406804 STLIGHT LINE&TRANS CONNECT REV	-1,209.13	-109.91	-1,319.04	-1,300.72	**-18.32**	**1**
406806 TRANS. CONNECTION UNMETERED	-372.02	-33.82	-405.84	-398.16	**-7.68**	**2**
471600 CONNECTION NETWORK CHARGE	124,068.21	13,651.11	137,719.32	139,063.75	**-1,344.43**	**-1**
500.18 Power purchased Connection	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0**
	-778,707.50	**-99,520.68**	**-878,228.18**	**-779,650.26**	**-98,577.92**	**13**

03/10/2013
11:05 AM

Prepared by	Detail Rev	Gen Rev
LCG 11/02/2013	AJB 15/02/2013	
Concur Rev	**4th Level Rev**	**Tax Rev**

REV-1

9-Staff-40

Ref: E9.T1.S. page 11 Account 1592, PILS & Tax Variances for 2006 and Subsequent Years CHEI is requesting disposition of the December 31, 2012 credit balance for Account 1592, PILS & Tax Variances for 2006 and Subsequent Years.

The filing requirements state "Distributors must complete and file Appendix 2-TA in support of their request to dispose of Account 1592."

Staff noted that CHEI provided Appendix 2-T, but did not provide the information to support the amount requested for disposition.

Please file Appendix 2-TA as required in the filing requirements.

Response: See Staff 37

9-Staff-41

Ref: E9.T1.S1 page 12 Account 1592, PILS & Tax Variances for 2006 and Subsequent Years, Sub Account HST/OVAT Input Tax Credits CHEI is requesting disposition of Account 1592, PILS & Tax Variances for 2006 and Subsequent Years, Sub Account HST/OVAT ITCs.

Staff noted that CHEI did not provide the balance of Account 1592, sub account HST/OVAT ITCs in the DVA Continuity Schedule as well as the analysis required. Please complete Appendix 2-TB for Account 1592, sub account HST/OVAT ITCs.

a) Please file the required analysis for the period July 1, 2010 to December 31, 2013 in Appendix 2-TB.

Response: See Staff 37

b) Please record the calculated balance in Account 1592, sub account HST/OVAT ITCs and please update the DVA Work Form.

Response: See Staff 37

9-Staff-42

Ref: Account 1576 Appendix 2-EE Accounting Changes Under CGAAP Revised Appendices 2-B, Old CGAAP: Fixed Asset Continuity Schedules for 2013 Revised Appendices 2-B, Revised CGAAP: Fixed Asset Continuity Schedules for 2013

Staff notes that the figures for the opening net PP&E and net additions in Appendix 2-EE are different from those used in Appendices 2-B under the former and revised CGAAP as shown in the table below. Staff also notes that CHEI used a positive sign rather than a negative sign for depreciation amounts in Appendix 2-EE under former and revised CGAAP.

In addition, CHEI did not calculate and file the separate rate riders for the disposition of the balance of Account 1576.

a) Please re-file Appendix 2-EE and other schedules, if any, after including the appropriate figures for the opening net PP&E, net additions, net depreciation (should be negative) and closing net PP&E.

Response Appendix 2-EE is presented at the next page and is also being filed in conjunction with these replies.

b) Please calculate and file the separate rate riders for the disposition of the balance of Account 1576.

Response; A rate revised rate rider is presented at the next page and is also reflected in the EDVVAR model filed in conjunction with these replies.

However, as explained in 9-VECC-44, CHEI maintains that disposing of account 1576 goes against Board policy that balances should be audited before they are disposed of and as such, CHEI is not seeking disposal of account 1576 in this proceeding and instead proposes to dispose of the balance in a future application.

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				2,017,237					
Net Additions - Note 4				295,900					
Net Depreciation (amounts should be negative) - Note 4				-146,612					
Closing net PP&E (1)				2,166,524					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				2,017,237					
Net Additions - Note 4				295,900					
Net Depreciation (amounts should be negative) - Note 4				-111,536					
Closing net PP&E (2)				2,201,600					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-35,076					

Effect on Deferral and Variance Account Rate Riders				
Closing balance in Account 1576	- 35,076		**WACC**	5.98%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 4,196			
Amount included in Deferral and Variance Account Rate Rider Calculation	- 39,272		**# of years of rate rider disposition period**	2

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) | **2** |

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576	
Residential	kWh	19,634,780	$ 29,454	**0.0008**	$/kWh
General Service < 50 kW	kWh	4,742,923	$ 2,586	**0.0003**	$/kWh
General Service > 50 to 4999 kW	**kW**	12,486	$ 181	**0.0073**	**$/kW**
Unmetered Scattered Load	kWh	89,208	$ 313	**0.0018**	$/kWh
Street Lighting	**kW**	1,003	$ 6,738	**3.3587**	**$/kW**
Total			**$ 39,272**		

9.0-VECC – 44

Reference: Exhibit 9, Tab 1, Letter of August 22

a) Embrun notes in this updated evidence that the amounts in account 1576 are unaudited and therefore disposition is contrary to Board policy. Please advise as to whether Embrun is seeking disposition of account 1576 in this proceeding.

Response: CHEI maintains that disposing of account 1576 goes against Board policy which dictate that balances should be audited before they are disposed. As such, CHEI is not seeking disposal of account 1576 in this proceeding and instead proposes to dispose of the balance in a future application.

Account 1556. Smart Meter related one-time costs.

CHEI is seeking to revise its application to dispose of its balance in account 1556. The costs relate to cost incurred by the utility to implement MDMR. The issue was addressed in detail in the Decision and Order issued by the OEB on July 23, 2013 and stated that;

"CHEI did not include any OM&A costs in its Application. In response to Board staff interrogatories, CHEI noted that it elected to waive its claim for operating costs in this Application. Board staff noted that this means that ongoing costs, primarily for data collection and verification and for TOU billing, will not be recovered until CHEI next rebases its rates through a cost of service application. VECC took no issue with CHEI's treatment of OM&A costs."

In an effort to explain why these costs were not included in the May 10th application, please note that the utility's accountants included theses costs in the EDVVAR model (in account 1556) however the model did not pick up the balance of this account in its rate rider calculations.

The total balance sought for disposition is in the amount of $165,834. Details of these expenses which total $101,924.82 along with depreciation and interest expenses are detailed at the next page.

The balance of account 1556 at December 31, 2012 reconciles with the utility's 2012 trial balance.

December 31, 2012 balances

155601	METER DATA MANAGEMENT REPOSITORY EXPENSES	101,924.82
155601-10	INTEREST METER DATA MANAGEMENT REPOSITORY EXPENSES	1,873.65
155602	DEPRECIATION EXPENSE SMART METER	62,035.82
	TOTAL	165,834.29

METER DATA MANAGEMENT REPOSITORY EXPENSES

2010		Company/Vendor	description	date	Amount
		via rail	training	August	$772.00
		Harris	meter sense	August	$9,000.00
		training mississauga	mdmr	August	$727.92
		Harris	mdmr	Oct	$2,250.00
		Brigitte Larocque	mdmr training	Nov	$219.25
		visa	mdmr	Dec	$302.08
		Brigitte Larocque	mdmr training	Nov	$783.24
			total expenses		$14,054.49
2011		Company/Vendor	description	date	Amount
		Brigitte Larocque	mdmr training	Feb	$140.00
		Cindy Léveillé	mdmr training	Feb	$70.00
		Harris	mdmr training	Feb	$525.00
		Harris	annual support	Feb	$1,200.00
		brigitte - cindy	mdmr training	Jan	$440.81
		brigitte	mdmr training	Feb	$68.00
		Cindy Léveillé	mdmr training	Feb	$68.00
		ginette patenaude	mdmr training	Feb	$775.00
		Harris	meter sense	Feb	$172.44
		Harris	meter sense	Feb	$344.88
		Util-Assist	mdmr training	Feb	$2,530.40
		Harris	mdmr training	Feb	$1,196.62
		ginette patenaude	mdmr training	March	$350.00
		Cindy Léveillé	meter sense	March	$94.00
		brigitte	meter sense	March	$45.00
		Brigitte Larocque	mdmr training	March	$194.00
		Harris	mdmr integration	August	$2,250.00
		Util-Assist	ieso integration	Sept	$4,200.00

		Harris	ms maintenance	August	$351.36
		Util-Assist	remote testing	July	$750.00
		Brigitte Larocque	mdmr training	August	$218.89
		Harris	Metersense	July	$351.18
		Util-Assist	remote testing	June	$750.00
		Util-Assist	remote testing	June	$960.00
		Util-Assist	ieso integration	June	$2,625.00
		Brigitte Larocque	mdmr training	June	$697.68
		Harris	meter sense	June	$350.64
		Util-Assist	ieso integration	June	$2,100.00
		visa	training	May	$353.05
		Util-Assist	ieso mdmr testing	May	$1,755.28
		Util-Assist	ieso integration	May	$2,100.00
		Harris	meters	May	$350.82
		Brigitte Larocque	mdmr	May	$191.00
		Util-Assist	ieso integration	April	$2,625.00
		Util-Assist	mileage & hotel exp.	April	$1,827.09
		Util-Assist	ieso & mdmr testing	April	$960.00
		Harris	Metersense	April	$344.88
		visa	brigitte training	April	$1,010.61
		visa	credit long distance cindy	April	-$66.70
		Benoit Lamarche	mileage	April	$210.00
		Brigitte Larocque	mileage	April	$315.00
		cindy leveille	mileage	April	$105.00
		Util-Assist	ieso integration	March	$2,100.00
		visa	brigitte training	March	$269.69
		Harris	meter sense	Feb	$344.88
		Harris	enable mvrs	March	$600.00
		Brigitte Larocque	mdmr testting	July	$944.00
		Harris	ms maintenance	Sept	$351.54
		Util-Assist	ieso integration	Sept	$2,641.17
		Harris	ms maintenance	Oct	$397.03
		Util-Assist	sync operator	Oct	$650.00
		ginete patenaude	mdmr trainng	Nov	$637.50
		Harris	ms maintenance	Nov	$351.36
		Util-Assist	sync operator	Nov	$672.35
		Brigitte Larocque	mileage	Dec	$190.00
		Harris	ms maintenance	Dec	$351.54
		visa	training pembroke	Dec	$425.31
		Util-Assist	training	Dec	$662.78
		Util-Assist	mileage & hotel exp.	Dec	$1,229.79
			total expenses		$62,773.36

2012		Company/Vendor	description	date	Amount
		Harris	mdmr support	Jan	$1,800.00
		impressions	flyers	Jan	$1,188.00
		ottawa river power	setup smart metering	Jan	$21,000.00
		visa	training	Feb	$589.87
		Util-Assist	consulting service	Jan	$651.80
		Harris	meters	Jan	$203.56
		Util-Assist	consulting service	Feb	$653.45
		Harris	meters	Feb	$351.54
		Harris	meters	March	$351.54
		Util-Assist	consulting service	March	$815.90
		visa	training mdmr	April	$1,351.51
		Brigitte Larocque	mileage	March	$239.00
		Harris	meters	April	$351.36
		Util-Assist	consulting service	April	$464.21
		Util-Assist	consulting service	May	$650.00
		Harris	meters	May	$351.36
		Util-Assist	consulting service	May	$653.15
		Harris	Metersense	June	$176.04
		Util-Assist	consulting service	June	$814.00
		Util-Assist	consulting service	July	$657.65
		Harris	Metersense	July	$351.72
		Harris	Metersense	August	$351.90
		Harris	Metersense	Sept	$352.08
		Util-Assist	consulting service	August	$650.00
		Util-Assist	education meeting	Sept	$86.47
		Util-Assist	consulting service	Sept	$814.90
		Harris	Metersense	Sept	$352.08
		Util-Assist	consulting service	Oct	$667.85
		Harris	Metersense	Nov	$352.44
		Util-Assist	consulting service	Nov	$666.32
		Harris	Metersense	Dec	$352.26
		Util-Assist	consulting service	Dec	$839.50
			total expenses		$101,924.82

Since the EDDVAR model does not allow the disposal of 1556, CHEI has calculated the rate rider outside of the model. The rate rider which uses the same allocation as other DVA accounts is presented below.

Please indicate the Rate Rider Recovery Period (in years) | **2** |

Rate Rider Calculation for Account 1556

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	19,634,780	$ 111,835	**0.0028**	$/kWh
General Service < 50 kW	kWh	4,742,923	$ 27,015	**0.0028**	$/kWh
General Service > 50 to 4999 kW	**kW**	12,486	$ 24,451	**0.9791**	**$/kW**
Unmetered Scattered Load	kWh	89,208	$ 508	**0.0028**	$/kWh
Street Lighting	**kW**	1,003	$ 2,025	**1.0095**	**$/kW**
		-	$ -	**-**	
Total			**$ 165,834**		

Appendix A – Letter from Northstar on MoE changes to the bill presentment.

MoE Standard Bill Print

Revision: 1.1

Contents

Purpose

This document will provide cost estimates around the Ministry of Energy's proposed bill presentment changes. The estimate is based on providing Ontario LDC's with a standard process in bill creation and printing from NorthStar CIS.

Requirements

The following are requirements gathered from the templates provided by the MoE. The requirements listed relate only to changes required to existing NorthStar bill printing processes.

Color Printing
Duplex Printing
Alternate Page Size
TOU usage charts/graphs (current, historical)
TOU pricing
Commodity charge breakdown (TOU, usage, rate, amount)
Other charges breakdown (amount)
Standard text/messages
Configurable text/messages

Observations

The example templates provided represent electric billed accounts only. It is assumed a separate page will be required to present other service details (meter, charges, etc…).

The example templates represent TOU billed electric accounts. LDC's may/will require different formats for other account types, e.g. GS, C&I, periodic

The proposed graphical representation of the usage data in a calendar (monthly) format may not coincide with the billing period. Representing data in a calendar month will require MDM/R integration, to retrieve the data in calendar month periods, instead of using historical CIS data stored in bill period format.

Rate changes will have to be considered in the commodity charge breakdown (where ON, OFF and MID usage, rate and amounts are shown).

Consideration for missing information from the proposed templates

- Budget (Equal payment) information is not depicted in the examples.
- Pre-authorized messages
- Retailer messages
- AMP information

The ‘previous charges’ section may be confusing if other services are included in this area, and new charges for these services are shown on another portion (or page) of the bill.

It will be assumed that LDC’s will aquire the hardware (printers) required to print colour, duplex, multiple page sizes and graphical representation of data.

Recommendations

Based on requirements, observations and existing custom bill print processes in the Ontario market, I recommend the following actions to accommodate the request for standardized electric bills as defined by the MoE.

1. The bill print process should be changed to generate a standard interface file (possibly XML format) which can be utilized by outsource printing solutions and internally for LDC’s printing their bills. This file will be designed to include all data elements required to produce a bill in any format.
2. LDC’s printing their own bills be required to purchase the NorthStar reporting tool (RAW) and utilize the standard interface file to produce bills.
3. LDC’s using an outsource printing solutions will need to obtain a cost estimate, from the provider, for reformatting their bill based on a new interface file.

Estimates

1. Define standard interface file as a XML Schema Definition (XSD)
   This will be a shared cost between participating LDC’s
   ~ $6k

2. Develop process to produce standard interface file
   This will be a shared cost between participating LDC’s
   ~ $22k

3. Purchase/Installation reporting tool (RAW)
   (not required for LDC’s using outsource printing)

License :	Less that 15k Customers ~ $16k
	15k to 40k Customers ~ $20k
Yearly Maintenance :	Less that 15k Customers ~ $2k
	15k to 40k Customers ~ $3k

4. Develop RAW bill rendering (for LDC’s not using outsource printing services)
   This will be a shared cost between participating LDC’s
   ~ $22k

Cost per LDC (if LDC bills more than electric service)
~ $11k

5. Implementation Support/Deployment
   Cost per LDC
   Implement process to create standard interface file
   ~ $7.5k

   Cost per LDC
   Implement RAW bill rendering (for LDC's not using outsource printing services)
   ~ $3k

Note: all values are approximate, and subject to change. This document is not to be considered as a contract or SOW for development and implementation of the MoE proposed bill format. The estimates are only to be used to assist LDC's in providing cost estimates to the EDA.

Appendix B – Bill Impacts

File Number:	EB-20130122
Exhibit:	8
Tab:	8
Schedule:	2
Page:	1
Date:	

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 13.70	1	$ 13.70	$ 14.00	1	$ 14.00	$ 0.30	2.19%
Smart Meter Rate Adder	Monthly	$ 1.44	1	$ 1.44		1	$ -	-$ 1.44	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.82	1	$ 0.82	$ 0.82	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0128	800	$ 10.24	$ 0.0160	800	$ 12.77	$ 2.53	24.68%
Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
LRAM	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
Deferred PILs 1562	per kWh	-$ 0.0008	800	-$ 0.64		800	$ -	$ 0.64	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 25.38			$ 27.59	**$ 2.21**	**8.70%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	800	-$ 1.68	-$ 0.0023	800	-$ 1.86	-$ 0.18	10.91%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0014	800	$ 1.12	$ 0.0019	800	$ 1.52	$ 0.40	35.71%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 24.82**			**$ 27.24**	**$ 2.42**	**9.77%**
RTSR - Network	per kWh	$ 0.0069	846	$ 5.84	$ 0.0057	853	$ 4.86	-$ 0.98	-16.74%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	846	$ 4.40	$ 0.0048	853	$ 4.09	-$ 0.31	-6.97%
Sub-Total C - Delivery (including Sub-Total B)				**$ 35.06**			**$ 36.20**	**$ 1.14**	**3.25%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	846	$ 3.72	$ 0.0044	853	$ 3.75	$ 0.03	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	846	$ 1.02	$ 0.0012	853	$ 1.02	$ 0.01	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			846	$ -		853	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	246	$ 21.68	$ 0.0880	253	$ 22.26	$ 0.58	2.70%
TOU - Off Peak		$ 0.0650	542	$ 35.21	$ 0.0650	546	$ 35.48	$ 0.28	0.78%
TOU - Mid Peak		$ 0.1000	152	$ 15.23	$ 0.1000	154	$ 15.35	$ 0.12	0.78%
TOU - On Peak		$ 0.1170	152	$ 17.82	$ 0.1170	154	$ 17.96	$ 0.14	0.78%
Total Bill on RPP (before Taxes)				**$ 106.73**			**$ 108.49**	**$ 1.76**	**1.65%**
HST		13%		$ 13.87	13%		$ 14.10	$ 0.23	1.65%
Total Bill (including HST)				$ 120.60			$ 122.59	$ 1.99	1.65%
Ontario Clean Energy Benefit [1]				-$ 12.06			-$ 12.26	-$ 0.20	1.66%
Total Bill on RPP (including OCEB)				**$ 108.54**			**$ 110.33**	**$ 1.79**	**1.65%**
Total Bill on TOU (before Taxes)				**$ 108.31**			**$ 110.03**	**$ 1.71**	**1.58%**
HST		13%		$ 14.08	13%		$ 14.30	$ 0.22	1.58%
Total Bill (including HST)				$ 122.39			$ 124.33	$ 1.93	1.58%
Ontario Clean Energy Benefit [1]				-$ 12.24			-$ 12.43	-$ 0.19	1.55%
Total Bill on TOU (including OCEB)				**$ 110.15**			**$ 111.90**	**$ 1.74**	**1.58%**

Loss Factor (%)	5.79%	6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS<50**

Consumption 2000 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after O

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 20.34	1	$ 20.34	$ 22.50	1	$ 22.50	$ 2.16	10.62%
Smart Meter Rate Adder	Monthly	$ 4.20	1	$ 4.20		1	$ -	-$ 4.20	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.85	1	$ 0.85	$ 0.85	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0168	2000	$ 33.60	$ 0.0081	2000	$ 16.20	-$ 17.40	-51.80%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
LRAM			2000	$ -		2000	$ -	$ -	
Deferred PILs 1562	per kWh	-$ 0.0008	2000	-$ 1.60		2000	$ -	$ 1.60	-100.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 56.54			$ 39.55	**-$ 16.99**	**-30.06%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	2000	-$ 4.20	-$ 0.0023	2000	-$ 4.56	-$ 0.36	8.52%
Global Adj DVA	per kWh	$ 0.0014	2000	$ 2.80	-$ 0.0007	2000	-$ 1.38	-$ 4.18	-149.35%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0013	2000	$ 2.60	$ 0.0016	2000	$ 3.20	$ 0.60	23.08%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 57.74**			**$ 36.81**	**-$ 20.93**	**-36.26%**
RTSR - Network	per kWh	$ 0.0064	2116	$ 13.54	$ 0.0053	2132	$ 11.30	-$ 2.24	-16.54%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2116	$ 9.73	$ 0.0042	2132	$ 8.96	-$ 0.78	-7.98%
Sub-Total C - Delivery (including Sub-Total B)				**$ 81.01**			**$ 57.06**	**-$ 23.95**	**-29.56%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2116	$ 9.31	$ 0.0044	2132	$ 9.38	$ 0.07	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2116	$ 2.54	$ 0.0012	2132	$ 2.56	$ 0.02	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2116	$ -		2132	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1516	$ 133.39	$ 0.0880	1532	$ 134.85	$ 1.46	1.10%
TOU - Off Peak		$ 0.0650	1354	$ 88.02	$ 0.0650	1365	$ 88.71	$ 0.69	0.78%
TOU - Mid Peak		$ 0.1000	381	$ 38.08	$ 0.1000	384	$ 38.38	$ 0.30	0.78%
TOU - On Peak		$ 0.1170	381	$ 44.56	$ 0.1170	384	$ 44.91	$ 0.35	0.78%
Total Bill on RPP (before Taxes)				**$ 271.50**			**$ 249.11**	**-$ 22.40**	**-8.25%**
HST		13%		$ 35.30	13%		$ 32.38	-$ 2.91	-8.25%
Total Bill (including HST)				$ 306.80			$ 281.49	-$ 25.31	-8.25%
Ontario Clean Energy Benefit [1]				-$ 30.68			-$ 28.15	$ 2.53	-8.25%
Total Bill on RPP (including OCEB)				**$ 276.12**			**$ 253.34**	**-$ 22.78**	**-8.25%**
Total Bill on TOU (before Taxes)				**$ 263.77**			**$ 241.25**	**-$ 22.52**	**-8.54%**
HST		13%		$ 34.29	13%		$ 31.36	-$ 2.93	-8.54%
Total Bill (including HST)				$ 298.06			$ 272.62	-$ 25.45	-8.54%
Ontario Clean Energy Benefit [1]				-$ 29.81			-$ 27.26	$ 2.55	-8.55%
Total Bill on TOU (including OCEB)				**$ 268.25**			**$ 245.36**	**-$ 22.90**	**-8.53%**

	Current	Proposed
Loss Factor (%)	5.79%	6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: GS>50

Consumption 100 kW ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 245.2700	1	$ 245.27	$ 235.00	1	$ 235.00	-$ 10.27	-4.19%
Smart Meter Rate Adder	Monthly	$ 14.3000	1	$ 14.30		1	$ -	-$ 14.30	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 4.5445	100	$ 454.45	$ 1.9785	100	$ 197.85	-$ 256.60	-56.46%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
LRAM	per kWh	$ 0.0284	100	$ 2.84		100	$ -	-$ 2.84	-100.00%
Deferred PILs 1562	per kWh	-$ 0.2605	100	-$ 26.05		100	$ -	$ 26.05	-100.00%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A				$ 690.81			$ 432.85	**-$ 257.96**	**-37.34%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.7109	100	-$ 71.09	-$ 0.7619	100	-$ 76.19	-$ 5.10	7.18%
Global Adj DVA	per kWh	$ 0.4834	100	$ 48.34	-$ 0.2375	100	-$ 23.75	-$ 72.09	-149.14%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge		$ 0.4778	100	$ 47.78	$ 0.6130	100	$ 61.30	$ 13.52	28.30%
Smart Meter Entity Charge						1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 715.84**			**$ 394.20**	**-$ 321.64**	**-44.93%**
RTSR - Network	per kWh	$ 2.5726	106	$ 272.16	$ 2.1331	107	$ 227.43	-$ 44.72	-16.43%
RTSR - Line and Transformation Connection	per kWh	$ 1.8286	106	$ 193.45	$ 1.6823	107	$ 179.37	-$ 14.08	-7.28%
Sub-Total C - Delivery (including Sub-Total B)				**$1,181.44**			**$ 801.00**	**-$ 380.44**	**-32.20%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	106	$ 0.47	$ 0.0044	107	$ 0.47	$ 0.00	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	106	$ 0.13	$ 0.0012	107	$ 0.13	$ 0.00	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			106	$ -		107	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	106	$ 7.93	$ 0.0750	107	$ 8.00	$ 0.06	0.78%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	68	$ 4.40	$ 0.0650	68	$ 4.44	$ 0.03	0.78%
TOU - Mid Peak		$ 0.1000	19	$ 1.90	$ 0.1000	19	$ 1.92	$ 0.01	0.78%
TOU - On Peak		$ 0.1170	19	$ 2.23	$ 0.1170	19	$ 2.25	$ 0.02	0.78%
Total Bill on RPP (before Taxes)				**$ 1,190.22**			**$ 809.85**	**-$ 380.37**	**-31.96%**
HST		13%		$ 154.73	13%		$ 105.28	-$ 49.45	-31.96%
Total Bill (including HST)				$ 1,344.95			$ 915.13	-$ 429.82	-31.96%
Ontario Clean Energy Benefit [1]				-$ 134.49			-$ 91.51	$ 42.98	-31.96%
Total Bill on RPP (including OCEB)				**$ 1,210.46**			**$ 823.62**	**-$ 386.84**	**-31.96%**
Total Bill on TOU (before Taxes)				**$ 1,190.82**			**$ 810.45**	**-$ 380.37**	**-31.94%**
HST		13%		$ 154.81	13%		$ 105.36	-$ 49.45	-31.94%
Total Bill (including HST)				$ 1,345.62			$ 915.81	-$ 429.82	-31.94%
Ontario Clean Energy Benefit [1]				-$ 134.56			-$ 91.58	$ 42.98	-31.94%
Total Bill on TOU (including OCEB)				**$ 1,211.06**			**$ 824.23**	**-$ 386.84**	**-31.94%**

Loss Factor (%) | Current: 5.79% | Proposed: 6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scatterred Load**

Consumption 500 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 40.01	1	$ 40.01	$ 9.75	1	$ 9.75	-$ 30.26	-75.63%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0104	500	$ 5.20	$ 0.0233	500	$ 11.66	$ 6.46	124.30%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Deferred PILs 1562	per kWh	-$ 0.0051	500	-$ 2.55		500	$ -	$ 2.55	-100.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A				$ 42.66			$ 21.41	**-$ 21.25**	**-49.80%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	500	-$ 1.05	-$ 0.0023	500	-$ 1.17	-$ 0.12	11.23%
Global Adj DVA	per kWh	$ 0.0014	500	$ 0.70	-$ 0.0007	500	-$ 0.35	-$ 1.05	-149.35%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge		$ 0.0013	500	$ 0.65	$ 0.0016	500	$ 0.80	$ 0.15	23.08%
Smart Meter Entity Charge								$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 42.96**			**$ 20.70**	**-$ 22.26**	**-51.82%**
RTSR - Network	per kWh	$ 0.0064	529	$ 3.39	$ 0.0053	533	$ 2.83	-$ 0.56	-16.54%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	529	$ 2.43	$ 0.0042	533	$ 2.24	-$ 0.19	-7.98%
Sub-Total C - Delivery (including Sub-Total B)				**$ 48.78**			**$ 25.76**	**-$ 23.01**	**-47.18%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	529	$ 2.33	$ 0.0044	533	$ 2.35	$ 0.02	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	529	$ 0.63	$ 0.0012	533	$ 0.64	$ 0.00	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			529	$ -		533	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	529	$ 39.67	$ 0.0750	533	$ 39.98	$ 0.31	0.78%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	339	$ 22.00	$ 0.0650	341	$ 22.18	$ 0.17	0.78%
TOU - Mid Peak		$ 0.1000	95	$ 9.52	$ 0.1000	96	$ 9.60	$ 0.07	0.78%
TOU - On Peak		$ 0.1170	95	$ 11.14	$ 0.1170	96	$ 11.23	$ 0.09	0.78%
Total Bill on RPP (before Taxes)				**$ 91.66**			**$ 68.98**	**-$ 22.68**	**-24.74%**
HST		13%		$ 11.92	13%		$ 8.97	-$ 2.95	-24.74%
Total Bill (including HST)				$ 103.58			$ 77.95	-$ 25.63	-24.74%
Ontario Clean Energy Benefit [1]				-$ 10.36			-$ 7.80	$ 2.56	-24.71%
Total Bill on RPP (including OCEB)				**$ 93.22**			**$ 70.15**	**-$ 23.07**	**-24.75%**
Total Bill on TOU (before Taxes)				**$ 94.66**			**$ 72.00**	**-$ 22.66**	**-23.94%**
HST		13%		$ 12.31	13%		$ 9.36	-$ 2.95	-23.94%
Total Bill (including HST)				$ 106.96			$ 81.36	-$ 25.60	-23.94%
Ontario Clean Energy Benefit [1]				-$ 10.70			-$ 8.14	$ 2.56	-23.93%
Total Bill on TOU (including OCEB)				**$ 96.26**			**$ 73.22**	**-$ 23.04**	**-23.94%**

Loss Factor (%)	5.79%	6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **StreetLights**

Consumption 1 **kW** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after O

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 1.60	1	$ 1.60	$ 2.25	1	$ 2.25	$ 0.65	40.63%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.5145	1	$ 6.51	$ 6.3991	1	$ 6.40	-$ 0.12	-1.77%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Deferred PILs 1562	per kW	-$ 0.5708	1	-$ 0.57		1	$ -	$ 0.57	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total A				$ 7.54			$ 8.65	**$ 1.11**	**14.65%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.7349	1	-$ 0.73	-$ 0.8249	1	-$ 0.82	-$ 0.09	12.25%
Global Adj DVA	per kW		1	$ -	-$ 0.2449	1	-$ 0.24	-$ 0.24	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.3694	1	$ 0.37	$ 0.4739	1	$ 0.47	$ 0.10	28.29%
Smart Meter Entity Charge								$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.18**			**$ 8.05**	**$ 0.87**	**12.19%**
RTSR - Network	per kWh	$ 1.9403	1	$ 2.05	$ 1.6088	1	$ 1.72	-$ 0.34	-16.43%
RTSR - Line and Transformation Connection	per kWh	$ 1.4136	1	$ 1.50	$ 1.3005	1	$ 1.39	-$ 0.11	-7.28%
Sub-Total C - Delivery (including Sub-Total B)				**$ 10.73**			**$ 11.16**	**$ 0.43**	**4.00%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1	$ 0.00	$ 0.0044	1	$ 0.00	$ 0.00	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1	$ 0.00	$ 0.0012	1	$ 0.00	$ 0.00	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1	$ -		1	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	1	$ 0.08	$ 0.0750	1	$ 0.08	$ 0.00	0.78%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	1	$ 0.04	$ 0.0650	1	$ 0.04	$ 0.00	0.78%
TOU - Mid Peak		$ 0.1000	0	$ 0.02	$ 0.1000	0	$ 0.02	$ 0.00	0.78%
TOU - On Peak		$ 0.1170	0	$ 0.02	$ 0.1170	0	$ 0.02	$ 0.00	0.78%
Total Bill on RPP (before Taxes)				**$ 11.06**			**$ 11.49**	**$ 0.43**	**3.88%**
HST		13%		$ 1.44	13%		$ 1.49	$ 0.06	3.88%
Total Bill (including HST)				$ 12.50			$ 12.98	$ 0.49	3.88%
Ontario Clean Energy Benefit [1]				-$ 1.25			-$ 1.30	-$ 0.05	4.00%
Total Bill on RPP (including OCEB)				**$ 11.25**			**$ 11.68**	**$ 0.44**	**3.87%**
Total Bill on TOU (before Taxes)				**$ 11.07**			**$ 11.50**	**$ 0.43**	**3.88%**
HST		13%		$ 1.44	13%		$ 1.49	$ 0.06	3.88%
Total Bill (including HST)				$ 12.51			$ 12.99	$ 0.49	3.88%
Ontario Clean Energy Benefit [1]				-$ 1.25			-$ 1.30	-$ 0.05	4.00%
Total Bill on TOU (including OCEB)				**$ 11.26**			**$ 11.69**	**$ 0.44**	**3.87%**
Loss Factor (%)		5.79%			6.62%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix C – Bill Impacts with disposition of 1556

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 13.70	1	$ 13.70	$ 14.00	1	$ 14.00	$ 0.30	2.19%
Smart Meter Rate Adder	Monthly	$ 1.44	1	$ 1.44		1	$ -	-$ 1.44	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.82	1	$ 0.82	$ 0.82	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0128	800	$ 10.24	$ 0.0160	800	$ 12.77	$ 2.53	24.68%
Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
LRAM	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
Deferred PILs 1562	per kWh	-$ 0.0008	800	-$ 0.64		800	$ -	$ 0.64	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 25.38			$ 27.59	**$ 2.21**	**8.70%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	800	-$ 1.68	-$ 0.0023	800	-$ 1.86	-$ 0.18	10.91%
			800	$ -		800	$ -	$ -	
Disposition of acct 1556	per kWh		800	$ -	$ 0.0028	800	$ 2.24	$ 2.24	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0014	800	$ 1.12	$ 0.0019	800	$ 1.52	$ 0.40	35.71%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 24.82**			**$ 29.48**	**$ 4.66**	**18.79%**
RTSR - Network	per kWh	$ 0.0069	846	$ 5.84	$ 0.0057	853	$ 4.86	-$ 0.98	-16.74%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	846	$ 4.40	$ 0.0048	853	$ 4.09	-$ 0.31	-6.97%
Sub-Total C - Delivery (including Sub-Total B)				**$ 35.06**			**$ 38.44**	**$ 3.38**	**9.64%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	846	$ 3.72	$ 0.0044	853	$ 3.75	$ 0.03	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	846	$ 1.02	$ 0.0012	853	$ 1.02	$ 0.01	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			846	$ -		853	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	246	$ 21.68	$ 0.0880	253	$ 22.26	$ 0.58	2.70%
TOU - Off Peak		$ 0.0650	542	$ 35.21	$ 0.0650	546	$ 35.48	$ 0.28	0.78%
TOU - Mid Peak		$ 0.1000	152	$ 15.23	$ 0.1000	154	$ 15.35	$ 0.12	0.78%
TOU - On Peak		$ 0.1170	152	$ 17.82	$ 0.1170	154	$ 17.96	$ 0.14	0.78%
Total Bill on RPP (before Taxes)				**$ 106.73**			**$ 110.73**	**$ 4.00**	**3.75%**
HST		13%		$ 13.87	13%		$ 14.39	$ 0.52	3.75%
Total Bill (including HST)				$ 120.60			$ 125.12	$ 4.52	3.75%
Ontario Clean Energy Benefit [1]				-$ 12.06			-$ 12.51	-$ 0.45	3.73%
Total Bill on RPP (including OCEB)				**$ 108.54**			**$ 112.61**	**$ 4.07**	**3.75%**
Total Bill on TOU (before Taxes)				**$ 108.31**			**$ 112.27**	**$ 3.95**	**3.65%**
HST		13%		$ 14.08	13%		$ 14.59	$ 0.51	3.65%
Total Bill (including HST)				$ 122.39			$ 126.86	$ 4.47	3.65%
Ontario Clean Energy Benefit [1]				-$ 12.24			-$ 12.69	-$ 0.45	3.68%
Total Bill on TOU (including OCEB)				**$ 110.15**			**$ 114.17**	**$ 4.02**	**3.65%**

Loss Factor (%) 5.79% 6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: GS<50

Consumption 2000 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after O

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 20.34	1	$ 20.34	$ 22.50	1	$ 22.50	$ 2.16	10.62%
Smart Meter Rate Adder	Monthly	$ 4.20	1	$ 4.20		1	$ -	-$ 4.20	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.85	1	$ 0.85	$ 0.85	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0168	2000	$ 33.60	$ 0.0081	2000	$ 16.20	-$ 17.40	-51.80%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
LRAM			2000	$ -		2000	$ -	$ -	
Deferred PILs 1562	per kWh	-$ 0.0008	2000	-$ 1.60		2000	$ -	$ 1.60	-100.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 56.54			$ 39.55	**-$ 16.99**	**-30.06%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	2000	-$ 4.20	-$ 0.0023	2000	-$ 4.56	-$ 0.36	8.52%
Global Adj DVA	per kWh	$ 0.0014	2000	$ 2.80	-$ 0.0007	2000	-$ 1.38	-$ 4.18	-149.35%
			2000	$ -		2000	$ -	$ -	
Disposition of acct 1556	per kWh		2000	$ -	$ 0.0028	2000	$ 5.60	$ 5.60	
Low Voltage Service Charge	per kWh	$ 0.0013	2000	$ 2.60	$ 0.0016	2000	$ 3.20	$ 0.60	23.08%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 57.74**			**$ 42.41**	**-$ 15.33**	**-26.56%**
RTSR - Network	per kWh	$ 0.0064	2116	$ 13.54	$ 0.0053	2132	$ 11.30	-$ 2.24	-16.54%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2116	$ 9.73	$ 0.0042	2132	$ 8.96	-$ 0.78	-7.98%
Sub-Total C - Delivery (including Sub-Total B)				**$ 81.01**			**$ 62.66**	**-$ 18.35**	**-22.65%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2116	$ 9.31	$ 0.0044	2132	$ 9.38	$ 0.07	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2116	$ 2.54	$ 0.0012	2132	$ 2.56	$ 0.02	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2116	$ -		2132	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1516	$ 133.39	$ 0.0880	1532	$ 134.85	$ 1.46	1.10%
TOU - Off Peak		$ 0.0650	1354	$ 88.02	$ 0.0650	1365	$ 88.71	$ 0.69	0.78%
TOU - Mid Peak		$ 0.1000	381	$ 38.08	$ 0.1000	384	$ 38.38	$ 0.30	0.78%
TOU - On Peak		$ 0.1170	381	$ 44.56	$ 0.1170	384	$ 44.91	$ 0.35	0.78%
Total Bill on RPP (before Taxes)				**$ 271.50**			**$ 254.71**	**-$ 16.80**	**-6.19%**
HST		13%		$ 35.30	13%		$ 33.11	-$ 2.18	-6.19%
Total Bill (including HST)				$ 306.80			$ 287.82	-$ 18.98	-6.19%
Ontario Clean Energy Benefit [1]				-$ 30.68			-$ 28.78	$ 1.90	-6.19%
Total Bill on RPP (including OCEB)				**$ 276.12**			**$ 259.04**	**-$ 17.08**	**-6.19%**
Total Bill on TOU (before Taxes)				**$ 263.77**			**$ 246.85**	**-$ 16.92**	**-6.41%**
HST		13%		$ 34.29	13%		$ 32.09	-$ 2.20	-6.41%
Total Bill (including HST)				$ 298.06			$ 278.95	-$ 19.12	-6.41%
Ontario Clean Energy Benefit [1]				-$ 29.81			-$ 27.89	$ 1.92	-6.44%
Total Bill on TOU (including OCEB)				**$ 268.25**			**$ 251.06**	**-$ 17.20**	**-6.41%**

Loss Factor (%)	5.79%	6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: GS>50

Consumption 100 kW ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge		$ 245.2700	1	$ 245.27	$ 235.00	1	$ 235.00	-$ 10.27	-4.19%
Smart Meter Rate Adder		$ 14.3000	1	$ 14.30		1	$ -	-$ 14.30	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 4.5445	100	$ 454.45	$ 1.9785	100	$ 197.85	-$ 256.60	-56.46%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
LRAM		$ 0.0284	100	$ 2.84		100	$ -	-$ 2.84	-100.00%
Deferred PILs 1562		-$ 0.2605	100	-$ 26.05		100	$ -	$ 26.05	-100.00%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A				$ 690.81			$ 432.85	**-$ 257.96**	**-37.34%**
Deferral/Variance Account Disposition Rate Rider		-$ 0.7109	100	-$ 71.09	-$ 0.7619	100	-$ 76.19	-$ 5.10	7.18%
Global Adj DVA		$ 0.4834	100	$ 48.34	-$ 0.2375	100	-$ 23.75	-$ 72.09	-149.14%
			100	$ -		100	$ -	$ -	
Disposition of acct 1556			100	$ -	$ 0.9791	100	$ 97.91	$ 97.91	
Low Voltage Service Charge		$ 0.4778	100	$ 47.78	$ 0.6130	100	$ 61.30	$ 13.52	28.30%
Smart Meter Entity Charge						1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 715.84**			**$ 492.11**	**-$ 223.73**	**-31.25%**
RTSR - Network	per kWh	$ 2.5726	106	$ 272.16	$ 2.1331	107	$ 227.43	-$ 44.72	-16.43%
RTSR - Line and Transformation Connection	per kWh	$ 1.8286	106	$ 193.45	$ 1.6823	107	$ 179.37	-$ 14.08	-7.28%
Sub-Total C - Delivery (including Sub-Total B)				**$1,181.44**			**$ 898.91**	**-$ 282.53**	**-23.91%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	106	$ 0.47	$ 0.0044	107	$ 0.47	$ 0.00	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	106	$ 0.13	$ 0.0012	107	$ 0.13	$ 0.00	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			106	$ -		107	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	106	$ 7.93	$ 0.0750	107	$ 8.00	$ 0.06	0.78%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	68	$ 4.40	$ 0.0650	68	$ 4.44	$ 0.03	0.78%
TOU - Mid Peak		$ 0.1000	19	$ 1.90	$ 0.1000	19	$ 1.92	$ 0.01	0.78%
TOU - On Peak		$ 0.1170	19	$ 2.23	$ 0.1170	19	$ 2.25	$ 0.02	0.78%
Total Bill on RPP (before Taxes)				**$ 1,190.22**			**$ 907.76**	**-$ 282.46**	**-23.73%**
HST		13%		$ 154.73	13%		$ 118.01	-$ 36.72	-23.73%
Total Bill (including HST)				$ 1,344.95			$ 1,025.76	-$ 319.18	-23.73%
Ontario Clean Energy Benefit [1]				-$ 134.49			-$ 102.58	$ 31.91	-23.73%
Total Bill on RPP (including OCEB)				**$ 1,210.46**			**$ 923.18**	**-$ 287.27**	**-23.73%**
Total Bill on TOU (before Taxes)				**$ 1,190.82**			**$ 908.36**	**-$ 282.46**	**-23.72%**
HST		13%		$ 154.81	13%		$ 118.09	-$ 36.72	-23.72%
Total Bill (including HST)				$ 1,345.62			$ 1,026.45	-$ 319.18	-23.72%
Ontario Clean Energy Benefit [1]				-$ 134.56			-$ 102.64	$ 31.92	-23.72%
Total Bill on TOU (including OCEB)				**$ 1,211.06**			**$ 923.81**	**-$ 287.26**	**-23.72%**

Loss Factor (%) 5.79% 6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scatterred Load**

Consumption 500 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 40.01	1	$ 40.01	$ 9.75	1	$ 9.75	-$ 30.26	-75.63%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0104	500	$ 5.20	$ 0.0233	500	$ 11.66	$ 6.46	124.30%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Deferred PILs 1562	per kWh	-$ 0.0051	500	-$ 2.55		500	$ -	$ 2.55	-100.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A				$ 42.66			$ 21.41	**-$ 21.25**	**-49.80%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	500	-$ 1.05	-$ 0.0023	500	-$ 1.17	-$ 0.12	11.23%
Global Adj DVA	per kWh	$ 0.0014	500	$ 0.70	-$ 0.0007	500	-$ 0.35	-$ 1.05	-149.35%
			500	$ -		500	$ -	$ -	
Disposition of acct 1556	per kWh		500	$ -	$ 0.0028	500	$ 1.40	$ 1.40	
Low Voltage Service Charge	per kWh	$ 0.0013	500	$ 0.65	$ 0.0016	500	$ 0.80	$ 0.15	23.08%
Smart Meter Entity Charge								$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 42.96**			**$ 22.10**	**-$ 20.86**	**-48.56%**
RTSR - Network	per kWh	$ 0.0064	529	$ 3.39	$ 0.0053	533	$ 2.83	-$ 0.56	-16.54%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	529	$ 2.43	$ 0.0042	533	$ 2.24	-$ 0.19	-7.98%
Sub-Total C - Delivery (including Sub-Total B)				**$ 48.78**			**$ 27.16**	**-$ 21.61**	**-44.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	529	$ 2.33	$ 0.0044	533	$ 2.35	$ 0.02	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	529	$ 0.63	$ 0.0012	533	$ 0.64	$ 0.00	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			529	$ -		533	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	529	$ 39.67	$ 0.0750	533	$ 39.98	$ 0.31	0.78%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	339	$ 22.00	$ 0.0650	341	$ 22.18	$ 0.17	0.78%
TOU - Mid Peak		$ 0.1000	95	$ 9.52	$ 0.1000	96	$ 9.60	$ 0.07	0.78%
TOU - On Peak		$ 0.1170	95	$ 11.14	$ 0.1170	96	$ 11.23	$ 0.09	0.78%
Total Bill on RPP (before Taxes)				**$ 91.66**			**$ 70.38**	**-$ 21.28**	**-23.22%**
HST		13%		$ 11.92	13%		$ 9.15	-$ 2.77	-23.22%
Total Bill (including HST)				$ 103.58			$ 79.53	-$ 24.05	-23.22%
Ontario Clean Energy Benefit [1]				-$ 10.36			-$ 7.95	$ 2.41	-23.26%
Total Bill on RPP (including OCEB)				**$ 93.22**			**$ 71.58**	**-$ 21.64**	**-23.21%**
Total Bill on TOU (before Taxes)				**$ 94.66**			**$ 73.40**	**-$ 21.26**	**-22.46%**
HST		13%		$ 12.31	13%		$ 9.54	-$ 2.76	-22.46%
Total Bill (including HST)				$ 106.96			$ 82.94	-$ 24.02	-22.46%
Ontario Clean Energy Benefit [1]				-$ 10.70			-$ 8.29	$ 2.41	-22.52%
Total Bill on TOU (including OCEB)				**$ 96.26**			**$ 74.65**	**-$ 21.61**	**-22.45%**

Loss Factor (%) 5.79% 6.62%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **StreetLights**

Consumption 1 **kW** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after O

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 1.60	1	$ 1.60	$ 2.25	1	$ 2.25	$ 0.65	40.63%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.5145	1	$ 6.51	$ 6.3991	1	$ 6.40	-$ 0.12	-1.77%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Deferred PILs 1562	per kW	-$ 0.5708	1	-$ 0.57		1	$ -	$ 0.57	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total A				$ 7.54			$ 8.65	**$ 1.11**	**14.65%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.7349	1	-$ 0.73	-$ 0.8249	1	-$ 0.82	-$ 0.09	12.25%
Global Adj DVA	per kW		1	$ -	-$ 0.2449	1	-$ 0.24	-$ 0.24	
			1	$ -		1	$ -	$ -	
Disposition of acct 1556			1	$ -	$ 1.0095	1	$ 1.01	$ 1.01	
Low Voltage Service Charge	per kW	$ 0.3694	1	$ 0.37	$ 0.4739	1	$ 0.47	$ 0.10	28.29%
Smart Meter Entity Charge								$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.18**			**$ 9.06**	**$ 1.88**	**26.25%**
RTSR - Network	per kWh	$ 1.9403	1	$ 2.05	$ 1.6088	1	$ 1.72	-$ 0.34	-16.43%
RTSR - Line and Transformation Connection	per kWh	$ 1.4136	1	$ 1.50	$ 1.3005	1	$ 1.39	-$ 0.11	-7.28%
Sub-Total C - Delivery (including Sub-Total B)				**$ 10.73**			**$ 12.16**	**$ 1.44**	**13.41%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1	$ 0.00	$ 0.0044	1	$ 0.00	$ 0.00	0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1	$ 0.00	$ 0.0012	1	$ 0.00	$ 0.00	0.78%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1	$ -		1	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	1	$ 0.08	$ 0.0750	1	$ 0.08	$ 0.00	0.78%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	1	$ 0.04	$ 0.0650	1	$ 0.04	$ 0.00	0.78%
TOU - Mid Peak		$ 0.1000	0	$ 0.02	$ 0.1000	0	$ 0.02	$ 0.00	0.78%
TOU - On Peak		$ 0.1170	0	$ 0.02	$ 0.1170	0	$ 0.02	$ 0.00	0.78%
Total Bill on RPP (before Taxes)				**$ 11.06**			**$ 12.50**	**$ 1.44**	**13.01%**
HST		13%		$ 1.44	13%		$ 1.63	$ 0.19	13.01%
Total Bill (including HST)				$ 12.50			$ 14.13	$ 1.63	13.01%
Ontario Clean Energy Benefit [1]				-$ 1.25			-$ 1.41	-$ 0.16	12.80%
Total Bill on RPP (including OCEB)				**$ 11.25**			**$ 12.72**	**$ 1.47**	**13.03%**
Total Bill on TOU (before Taxes)				**$ 11.07**			**$ 12.51**	**$ 1.44**	**13.00%**
HST		13%		$ 1.44	13%		$ 1.63	$ 0.19	13.00%
Total Bill (including HST)				$ 12.51			$ 14.13	$ 1.63	13.00%
Ontario Clean Energy Benefit [1]				-$ 1.25			-$ 1.41	-$ 0.16	12.80%
Total Bill on TOU (including OCEB)				**$ 11.26**			**$ 12.72**	**$ 1.47**	**13.02%**

Loss Factor (%) 5.79% 6.62%

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