COOPÉRATIVE HYDRO EMBRUN INC. (CHE) 2010 RATE APPLICATION
Board File No. EB-2009-0132
Interrogatories of the Vulnerable Energy Consumers' Coalition ("VECC")

-CHE RESPONSES-

<u>Question #1</u>

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

a) Please provide the number of smart meters installed to date in 2009 and the number yet to be installed in 2009.

CHE Response.
At December 9, 2009 all smart meters have been installed.

b) Please provide the costs incurred to date on smart meter installation and the expected total cost of smart meter installation.

CHE Response.
$305,198. This amount includes the cost of installation for all meters.

<u>Question #2</u>

Reference: Exhibit 1/Tab 4/Schedule 1, page 4

a) Please provide the rationale for valuing inventory "at the lower of average cost and replacement cost."

BDO Response (on behalf of CHE)
The accounting policy that we see the most often in general practice for the inventory is at the lower of cost and realizable value. In this case for CHE they chose lower of average cost and replacement cost for the following reasons:

1. They have in inventory meters and cables that are purchase at different dates. The average cost makes most sense to calculate the cost. The transformers are valued at actual cost.
2. They use replacement cost instead of realizable value since they will never sell the inventory since it is used in their system.

Question #3

Reference: Exhibit 2 and Exhibit 4

a) Has CHE reflected any expected impacts of the announced July 1, 2010 harmonization of the GST with the RST in its 2010 revenue requirement? If so, please identify and quantify; if not, please explain why not.

CHE Response
CHE does not expect any material impact with respect to the harmonization of GST and PST, the only cost will be to add a PST field in the CIS System and CHE believe that it will not affect the revenue requirement.

Question #4

Reference: Exhibit 2/Tab 4/Schedule 2, page 2

a) Please explain why a one-year cycle is used for tree trimming, as opposed to a longer cycle.

CHE Response
CHE would like to clarify that its service area is divided in four sections, internally referred to as "cycle". A single section is patrolled every year and the entire service area is patrolled over a four year cycle.

Question #5

Reference: Exhibit 3/Tab 1/Schedule 1, Attachment 2

a) With respect to page 2, please explain why class retail data for Embrun is only available on an annual basis. a)

CHE Response
Monthly retail data is not available. Embrun bills its customers on a bi-monthly basis and the system provides historical data on an annual basis. It may be possible to get some data on a quarterly basis if necessary.

b) What other model specifications did Embrun/ERA test and did any of them include population or customer count as an explanatory variable? Please indicate the results of each in a format similar to that used on page 5. Steven

CHE Response
Embrun/ERA did not test any model specifications that included population or customer count as an explanatory variable. Customer count was not tested due to the fact that Embrun does not have monthly customer count data. In order to correctly model weather effects, monthly observations are necessary. In addition, it has been the ERA consultant's experience that employment serves as a better variable for economic activity than customer count in most cases. Inclusion of customer

count often yields counter-intuitive results (such as the wrong sign on the coefficient), statistically insignificant estimates, and less accurate within sample forecasts. For example, see Case Number EB-2008-0221, Bluewater Power Distribution Corporation Response to VECC Interrogatories 16 (e), pp.52-53, December 22, 2008.

Population was not included as we are unaware if monthly population counts for Embrun are available. Official population counts occur in Canada only every 5 years during the Census. Between census years, intercensal population estimates are provided by Statistics Canada and possibly provincial sources as well. However, these are estimates based on statistical models, not counts, and we are unsure if they are available monthly or for Embrun. It is also unclear to us prima facie, why population would be superior to employment in representing changes in economic activity levels.

Embrun tested several variations of the model ultimately chosen. These included models with only HDD, CDD and employment; and HDD, CDD, employment and peak days. These are referred to as Model 1 and Model 2. Model 3 is the chosen model which also includes dummy variables for December (likely due to high prevalence of Christmas lighting) and summer (increasing prevalence of central air). The dummy variables increase the consumption during these periods and reflects consumption variations not reflected in weather or economic activity. Results of the first 2 models are displayed below:

```
Model 1: OLS, using observations 2002:05-2008:12 (T = 80)
Dependent variable: WholesalekWh

               coefficient     std. error    t-ratio    p-value
  --------------------------------------------------------------
  const         -1.00229e+06   420152        -2.386     0.0195    **
  HDD         1922.70              85.5050   22.49      2.53e-035 ***
  CDD         6009.32             679.798     8.840     2.70e-013 ***
  FTE_OTTREG  4986.03             798.142     6.247     2.21e-08  ***

R-squared            0.882407   Adjusted R-squared   0.877766
F(3, 76)             190.0997   P-value(F)           3.12e-35
rho                 -0.049088   Durbin-Watson        2.093971

Model 2: OLS, using observations 2002:05-2008:12 (T = 80)
Dependent variable: WholesalekWh

               coefficient   std. error    t-ratio    p-value
  -----------------------------------------------------------
  const         403334       530972         0.7596    0.4499
  HDD             1900.19        78.8375   24.10      4.69e-037 ***
  CDD             6142.69       626.025     9.812     4.31e-015 ***
  PeakDays      -67174.8      17407.8      -3.859     0.0002    ***
  FTE_OTTREG      4993.90       733.890     6.805     2.15e-09  ***

R-squared            0.901887   Adjusted R-squared   0.896655
F(4, 75)             172.3568   P-value(F)           5.39e-37
rho                  0.122641   Durbin-Watson        1.746236
```

In addition to using the adjusted R-squared statistic, another statistic considered is Theil's U. We present the Theil's U (U^2) statistic for the 3 models below:

Model 1, U^2=0.44
Model 2, U^2=0.40
Model 3 (chosen) U^2=0.35.

The more accurate the forecast, the lower the U^2 statistic is, with $U^2=1$ equivalent to a naïve forecast.

In addition to using the adjusted R-squared statistic, another statistic considered is Theil's U. We present the Theil's U (U2) statistic for the 3 models below:

Model 1, U2=0.44
Model 2, U2=0.40
Model 3 (chosen) U2=0.35.

The more accurate the forecast, the lower the U2 statistic is, with U2=1 equivalent to a naïve forecast.

c) Please provide a schedule that compares the annual growth in Ontario Employment for each year from 2002 to 2008 with yearly growth rates in employment in the Ottawa Region for the same period.

CHE Response

Percentage Change, Annual Average Employment

Year	*Full-time employment, Ontario (v2054816)*	*Full-time employment, Ottawa Region (v2054772)*
2002	1.0%	-1.1%
2003	2.8%	3.7%
2004	2.3%	0.4%
2005	1.2%	1.2%
2006	2.0%	3.2%
2007	1.1%	2.2%
2008	0.9%	2.6%

d) With respect to page 8, please indicate the date of publication for each of the Employment forecasts used. Also, please provide any more recent forecasts that are available

CHE Response
Table 6 on Page 8 of the ERA Load Forecast Report indicates the date of the forecast for each of the chartered banks. These were the most current available to us at the time the Embrun load forecast was prepared. We are unsure whether this date refers to the date of publication or the date the forecast was completed. Each of these forecasts are updated on a periodic basis and are available at the chartered bank websites free of charge:

BMO:
http://www.bmonesbittburns.com/economics/forecast/prov/ProvincialOutlook.pdf

RBC:

http://www.rbc.com/economics/quicklink/pdf/provtbl.pdf

Scotia:
http://www.scotiacapital.com/English/bns_econ/ptrends.pdf

TD:
http://www.td.com/economics/qef/prov1109.pdf

e) With respect to pages 9-10, please provide more details as how the weather normalized use by class was established for the historical years 2003-2008.
   - What assumptions were used regarding the weather sensitivity of each class' load and what was the basis for these assumptions?
   - Using one year's data (e.g., 2008), please provide a working example.

CHE Responses:
We refer to page 2 of the ERA Report where it is noted that;

> *[w]hile ERA believes it is desirable to isolate demand determinants related to individual rate classes, it is not always possible to do this due to the data limitations imposed by using class-level billing data.*

Since historical monthly retail data for Embrun was not available, it was not possible to derive class specific forecasting equations. Rather, an aggregate model based on wholesale purchases was developed, as outlined on p.2 of the ERA Report. Therefore, weather sensitivity for all weather sensitive classes is assumed to be the same. We also note that the OEB has approved this type of load forecast methodology in the past for a number of LDC's rebasing applications where monthly class specific data was not available, or problematic, so this is not a new or novel approach.

Question #6

Reference: Exhibit 3/Tab 1/Schedule 2, Attachment 1

a) What is the basis for the $0.06072 commodity cost assumed for 2010?

CHE Response;
At the time of the submission, CHE used the most up to date information available which was the Regulated Price Plan ("RPP") commodity price as indicated in the Regulated Price Plan (RPP) Prices (as issued by the OEB on April 15, 2009. The average RPP price in the report was $.06072 per kWh. Since then, the OEB has issued its bi-annual commodity price update:
http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Regulated+Price+Plan
These new RPP rates (per kWh) are $0.058 and $0.067.
CHE proposes to update its commodity cost to reflect the new RPP rates. The resulting changes are reflected in the amended rate models and these models will be filed when required.

b) Based on the most recent 12 months data, what percentage of Embrun's sales (kWh) are to RPP customers?

CHE Response
Based on the most recent 12 months data, the percentage of kWh sales to RPP customers is 93.6%.

<u>Question #7</u>

Reference: Exhibit 3/Tab 2/Schedule 1, Attachment 1

a) Please provide a breakdown of the 2010 -related revenues at existing rates ($37,000) by customer class.

CHE Response
The projection for 2009 and 2010 LV Charges were based on the historical costs. CHE projected LV charges for 2009 that were consistent with past years

	2008	2007	2006
4750-Charges-LV	36,609.46	37,456.56	20,284.64

Note that the reason why LV charges were lower in 2006 due to the fact that the charge came into effect following a May 1st rate order.

Please find below a approximation, per class, of projections for LV Charges at existing rates

Customer Class Name	Low Voltage Charges [7]
Residential	25,269
General Service Less Than 50 kW	5,802
General Service 50 to 4,999 kW	5,467
Unmetered Scattered Load	109
Street Lighting	353
TOTAL	**37,000**

b) Please provide a revised schedule that sets out 2010 revenues at 2009 rates, where the rates exclude the LV rate adder.

c) Please revise the calculation of the Fixed vs. Variable percentages by customer class for 2010 at existing rates using variable rates that exclude the LV rate adder.

CHE Response b) c)
See results tables in the pages following CHE's answer to d).

d) Please reconcile any differences between the revenue by class reported here and those used in Sheet O1 of the 2010 Cost Allocation model.

CHE Response d)
CHE respectfully requests that questions involving the Cost Allocation be answered once the proposed updates to the revenue requirement have been finalized. Any changes to the revenue requirement ultimately affect the CA results and the time and resources required to update the cost allocation information are substantial and can add unnecessary costs to the process

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

2010 EDR Application (EB-2009-0132) version: v0.1

December 9th Response to Interrogatories

EXCLUDING LV CHARGES

F4 Revenue Requirement Allocation

Enter the outstanding Base Revenue Requirement and Transformer Allowance recoveries by customer class

Customer Class Name	Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement $ [3]			Directly Assigned Revenues [3]	Total Base Revenue Requirement
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application		
Residential	67.38%	71.20%	69.45%	516,246	545,441	532,094		532,094
General Service Less Than 50 kW	16.94%	15.04%	15.49%	129,781	115,191	118,705		118,705
General Service 50 to 4,999 kW	9.73%	12.03%	11.74%	74,544	92,177	89,950		89,950
Unmetered Scattered Load	2.71%	0.49%	1.38%	20,728	3,751	10,578		10,578
Street Lighting	3.24%	1.25%	1.93%	24,818	9,558	14,790		14,790
TOTAL	**100.00%**	**100.00%**	**100.00%**	**766,118**	**766,118**	**766,118**		**766,118**
			OK			**OK**		

[1] from sheet F3
[2] from sheet C4
[3] from sheet F2

Customer Class Name	Total Base Revenue Requirement	Transformer Allowance Recovery [4]	Low Voltage Revenue Required [5]	Gross Base Revenue Requirement
Residential	532,094			532,094
General Service Less Than 50 kW	118,705			118,705
General Service 50 to 4,999 kW	89,950			89,950
Unmetered Scattered Load	10,578			10,578
Street Lighting	14,790			14,790
TOTAL	**766,118**			**766,118**
		OK		

2010 Transformer Allowances

	Volume [4]	Rate	Amount
kW:			

[4] Volume per sheet C4; total allocations must match total amount of allowances
[5] allocated per table below:

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

2010 EDR Application (EB-2009-0132) version: v0.1

December 9th Response to Interrogatories

F4 Revenue Requirement Allocation

Enter the outstanding Base Revenue Requirement and Transformer Allowance recoveries by customer class

Customer Class Name	Test Year Revenues [6] Transmission - Connection	Class Share	Low Voltage Charges [7]
Residential	90,241	68.3%	
General Service Less Than 50 kW	20,719	15.7%	
General Service 50 to 4,999 kW	19,524	14.8%	
Unmetered Scattered Load	389	0.3%	
Street Lighting	1,259	1.0%	
TOTAL	**132,133**	**100.0%**	
		OK	

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

2010 EDR Application (EB-2009-0132) version: v0.1

September 15, 2009

INCLUDING LV CHARGES

F4 Revenue Requirement Allocation

Enter the outstanding Base Revenue Requirement and Transformer Allowance recoveries by customer class

Customer Class Name	Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement $ [3]			Directly Assigned Revenues [3]	Total Base Revenue Requirement
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application		
Residential	67.38%	71.20%	69.45%	516,558	545,770	532,415		532,415
General Service Less Than 50 kW	16.94%	15.04%	15.49%	129,859	115,261	118,777		118,777
General Service 50 to 4,999 kW	9.73%	12.03%	11.74%	74,589	92,232	90,004		90,004
Unmetered Scattered Load	2.71%	0.49%	1.38%	20,741	3,753	10,585		10,585
Street Lighting	3.24%	1.25%	1.93%	24,833	9,564	14,798		14,798
TOTAL	**100.00%**	**100.00%**	**100.00%**	**766,580**	**766,580**	**766,580**		**766,580**
			OK			**OK**		

[1] from sheet F3
[2] from sheet C4
[3] from sheet F2

Customer Class Name	Total Base Revenue Requirement	Transformer Allowance Recovery [4]	Low Voltage Revenue Required [5]	Gross Base Revenue Requirement
Residential	532,415		28,001	560,417
General Service Less Than 50 kW	118,777		6,429	125,206
General Service 50 to 4,999 kW	90,004		6,058	96,062
Unmetered Scattered Load	10,585		121	10,706
Street Lighting	14,798		391	15,189
TOTAL	**766,580**		**41,000**	**807,580**
		OK		

2010 Transformer Allowances

	Volume [4]	Rate	Amount
kW:			

[4] Volume per sheet C4; total allocations must match total amount of allowances
[5] allocated per table below:

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

2010 EDR Application (EB-2009-0132) version: v0.1

September 15, 2009

F4 Revenue Requirement Allocation

Enter the outstanding Base Revenue Requirement and Transformer Allowance recoveries by customer class

Customer Class Name	Test Year Revenues [6] Transmission - Connection	Class Share	Low Voltage Charges [7]
Residential	90,241	68.3%	28,001
General Service Less Than 50 kW	20,719	15.7%	6,429
General Service 50 to 4,999 kW	19,524	14.8%	6,058
Unmetered Scattered Load	389	0.3%	121
Street Lighting	1,259	1.0%	391
TOTAL	**132,133**	**100.0%**	**41,000**
		OK	

Question #8

Reference: i) Exhibit 7 (ERA Report), page 11

a) Please provide a schedule that sets out the revenue to costs ratios for 2010 assuming the 2009 rates were all increased by the same percentage so that total Service Revenue equals the total Revenue Requirement for 2010. (Note: This can be achieved by increasing each class' Distribution revenues in Sheet O1 by approximately 24.6%)

Customer Class	CHE-2006	CHE-2006C	CHE-2010 At 2009 Rates	**CHE-2010 With uniform Increase**	CHE-2010 At proposed 2010 Rates	Board Target Range
Residential	105.78	105.78	87. 71	**105.56**	102.88	85-115
GS < 50 kW	91.08	91.08	74.27	**89.38**	92.10	80-120
GS > 50 kW	121.05	121.05	99.85	**120.17**	119.43	80-180
Street Lighting	49.63	49.63	35.34	**42.53**	60.70	70-120
USL	21.48	21.48	19.76	**23.78**	54.71	80-120
Total	100.00	100.00	83.09	**100.00**	100.00	-

The above table is based on the CA information that was filed in conjunction with the September 17 submission.

CHE respectfully requests that questions involving the Cost Allocation be answered once the proposed updates to the revenue requirement have been finalized. Any changes to the revenue requirement ultimately affect the CA results and the time and resources required to update the cost allocation information are substantial and can add unnecessary costs to the process.

<u>Question #9</u>

Reference: Exhibit 4/Tab 2/Schedule 2

Issue 4.3 International Financial Reporting Services ("IFRS")
13 Ref: Exhibit(s) Exhibit 4 Tab 2 Schedule 2

CHE state that it estimates that the one-time cost for converting to IFRS is $60,000 and that they propose to amortize the cost over four years. Will CHE remove these costs and use a deferral account as stated on page 27 in Report of the Board Transition to International Financial Reporting Standards, EB-2009-0408, July 28, 2009?

CHE Response
Please see CHE related responses to Board Staff Interrogatories copied below.

"CHE was not aware of these changes and is therefore proposing to remove this cost from the rebasing application and use a deferral account as stated by the Board. If approved, the impact to the revenue requirement would be a reduction of $15,184 (from $766,580 to $751,396). This decrease includes adjustments to PILs. If approved, these revised costs will be updated in the rate models and the models provided upon request"

a) Please explain how the $60K cost estimated to transition to IFRS was estimated.

CHE Response: N/A

b) Please indicate the stage/phase of IFRS implementation (or pre-implementation) that CHE is at, along with the costs incurred to date.

CHE Response: N/A

c) Please indicate the party or parties that CHE has selected for its IFRS project and explain how the party or parties were chosen.

CHE Response: N/A

Question #10

Reference: Exhibit 4/Tab 2/Schedule 3, page 3

a) CHE has included an incremental cost of $5,000 for "Expert Witness cost for regulatory matters. In the event that an oral hearing is not required, does CHE agree that this cost should be removed from its rebasing costs?

CHE Response
Please see CHE related responses to Board Staff Interrogatories copied below.

Update: CHE is requesting an update to the projected regulatory costs requested in its September 17th application to the Board.

The decision to update its costs was brought about following a review of the cost of drafting interrogatories responses. CHE has found that certain interrogatories required more resources than first expected. Also, CHE inadvertently overlooked certain regulatory costs that CHE are still expecting to incur. CHE is proposing to increase the cost of rebasing from $120,000 to $130,000

If approved, the impact to the revenue requirement would be an increase of $2,530 (from $766,580 to $769,110). This increase includes adjustments to PILs. If approved, these revised costs will be updated in CHE's rate models and the models provided upon request.

Please find below an update of the costs which is comprised of the removal of the cost of an expert witness; originally projected at $5,000, a new separate cost of $5000 for intervener costs, a revised separate cost of $15,000 for drafting responses to IRs and a projected $5000 for written submissions.

Total cost of rebasing		
*Expert Witness **		*$ 0*
Consultants costs for regulatory matters		***$ 110,000.00***
Evidence Drafting		***$ 80,000.00***
Load Forecast		*$ 5,000.00*
Revisions to Cost Allocation		*$ 5,000.00*
*Interrogatories **		*$ 15,000.00*
*Written Submission **		*$ 5,000.00*
Intervener costs for regulatory matters		***$ 5,000.00***
*Intervener cost 22hrs X$225 **		*$ 5,000.00*
Other Costs		***$ 5,000.00***
rate order		*$ 5,000.00*

Operating expenses associated with other resources allocated to regulatory matters (please identify the)		***$ 10,000.00***
2010 EDR Model		*$ 10,000.00*
2012 EDR Total		***$ 130,000.00***

Question #11

Reference: Exhibit 4/Tab 4/Schedule 1, Attachment 1

The referenced evidence indicates that OM&A charges for employee costs were $151,052.04 in 2007, rising to $172,571 in 2009, and rising further to $181,355 in the 2010 Test Year.

a) Please confirm that the rise over the two-year period 2007-09 reflects an annual increase of 6.89% per year (compounded).

CHE Response: The numbers have been updated. Please refer to the table at the following page for revised numbers. The revised 2-year rise reflects a compounded growth rate of 4.85%

b) Please confirm that the rise over the three-year period 2007-10 reflects an annual increase of 6.28% per year (compounded).

CHE Response: The numbers have been updated. Please refer to the table at the following page for revised numbers. The revised 3-year rise reflects a compounded growth rate of 3.27%

c) Please provide a detailed explanation for the magnitudes of the increases cited in a) and b).

CHE Response:
CHE has revised its evidence and submits this update table (see next page) and offers the following explanation for the increase. The increase between 2007 and 2008 is due to the fact that both CSRs employed with CHE in 2007 left the utility; one resigned and the other retired. Thus 2 new employees were hired. This caused CHE to incur costs in training and overtime. At the same time, the board of directors also revised and adjusted employee salaries and benefits package that had remained unchanged since 2001.

d) Please explain why there were 3.5 FTEs in 2008 and 3 FTEs in 2009 yet the total employee costs decreased by less than $2,300 in 2009.

CHE Response:
The 3.5 FTE was a typing error. The actual number of FTE for 2008 was 3.

Number of Employees:

Description	2006 EDR		2006 Actual		2007 Actual		2008 Actual		2009 Bridge		2010 Test
FTE	2		3		3		3		3		3
Union	0		0		0		0		0		0

Compensation (Salary and Wages):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test
FTE	$ 109,732.00	$ 109,732.00	$ 143,274.00	$ 143,274.00	$ 148,155.00	$ 148,155.00	$ 166,836.00	$ 166,836.00	$ 162,871.00	$ 162,871.00	$ 163,147.46
Union											

Compensation (Benefits):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test
FTE	$ 5,722.00	$ 5,722.00	$ 3,835.00	$ 3,835.00	$ 2,897.04	$ 2,897.04	$ 8,000.00	$ 8,000.00	$ 9,700.00	$ 9,700.00	$ 10,000.00
Union											

Compensation (Incentives):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test
FTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union											

Total (Salary and Wages, Benefits & Incentives):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test
FTE	$ 115,454.00	$ 115,454.00	$ 147,109.00	$ 147,109.00	$ 151,052.04	$ 151,052.04	$ 174,836.00	$ 174,836.00	$ 172,571.00	$ 172,571.00	$ 173,147.46
Union											

Costs Charged to OM&A:

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test
FTE	$ 115,454.00	$ 115,454.00	$ 147,109.00	$ 147,109.00	$ 151,052.04	$ 151,052.04	$ 174,836.00	$ 174,836.00	$ 172,571.00	$ 172,571.00	$ 173,147.46
Union											

Excerpt from 2006 EDR Handbook: "*Where there are three, or fewer, full-time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs.*"

Question #12

Reference: Exhibit 8/Tab 2/Schedule 1, page 1

NOTE: CHE confirm that the information at Exhibit 8/Tab 2/Schedule 1 was based on an outdated version of the cost allocation. CHE proposes to update its evidence and models accordingly. The update models will be provided when required.

CHE respectfully requests that questions related to Cost Allocation be answered once the proposed updates to the revenue requirement have been finalized. Any changes to the revenue requirement ultimately affect the CA results and the time and resources required to update the cost allocation information are substantial and can add unnecessary costs to the process.

a) Please provide a schedule that sets out the proposed 2010 revenue to cost ratios by class and compares them with the results from Question #8.

CHE Response: to be determined once revenue requirements have been finalized - see above note

b) Please provide a schedule that reconciles the Base Distribution Revenue Requirement allocated to each class for 2010 with the proposed revenue to cost ratios.

CHE Response: to be determined once revenue requirements have been finalized - see above note

c) Page 2 makes reference to a 1.06 Revenue to Cost ratio for the Residential class based the Cost Allocation file. Please provide the source/reference document.

CHE Response: the ratio should have originated from the CHE-2010 EMBRUN_DETAILED_CA_Model_Run 2. The information at page 2 of this particular schedule was outdated and should have been updated. CHE proposes to update this schedule once updates to the revenue requirement have been finalized.

d) Please explain how Embrun determined that the starting point for the Street Lighting revenue to cost ratio was 0.47.

CHE Response:
CHE confirm that the Street Lighting revenue to cost ratio of 0.47 was outdated and incorrect. Evidence should have been consistent with Run 2 of the revised cost allocation model; namely row 80 of Sheet O1 of CHE-2010 EMBRUN_DETAILED_CA_Model_Run 2
Please note that the cost allocation models will have to be updated if any changes to the revenue requirement occur. CHE proposes to update the information in its models only when revisions to the revenue requirement have been approved.

e) What was the starting point used for the USL class and how was it established?

CHE Response:
Please see response to d) Similarly, the starting point for the USL class should have come from the information in Run 2 of the revised cost allocation model; namely row 80 of Sheet O1 of CHE-2010 EMBRUN_DETAILED_CA_Model_Run 2 .

f) Why were the revenue to cost ratios for the GS classes held fixed while the ratio for Residential was decreased?

CHE Response:
As mentioned, the information at Exhibit 8/Tab 2/Schedule 1 was outdated. CHE requests that questions related to Cost Allocation be answered once the proposed updates to the revenue requirement have been finalized. However, CHE would like to state that at the time, it lowered the ratio for the Residential Class in order to move it closer to a ratio of 1.00

Question #13

Reference: Exhibit 8/Tab 2/Schedule 1, page 1 and Attachment 1

a) Please confirm that the Board's EB-2007-0667 Guideline (page 12) sets the upper limit for the MSC at 120% of avoided costs plus the allocated customer costs (i.e., Minimum System plus PLCC Adjustment). Based on this definition, would either the Residential or GS>50 service charge exceed the Board's threshold if derived using the existing fixed-variable split?

CHE Response;
CHE does not believe that the guideline sets the upper limit for the MSC as stipulated in the question. The Board noted in its report that such a limit had been proposed by Board staff, but added "The Board considers it to be inappropriate to make significant changes to the ceiling for the MSC at this time". Thus CHE has relied on the maximum value generated from the Board's approved Cost Allocation model as the ceiling for the MSC. Furthermore, the guideline also states that "Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level". Thus the existing MSC rate constitutes the effective ceiling, when it exceeds the maximum value from the Cost Allocation model.

b) Please confirm whether the fixed-variable splits at existing rates set out in Attachment 1 are based on variable rates that include the LV rate adder. If yes, please re-do the schedule with using existing variable rates that exclude the LV rate adder.

CHE Response
The fixed-variable splits at existing rates set out in Attachment 1 are based on variable rates that include the LV charges. Please see response to #7 to see the schedule using existing variable rates that exclude the LV rate adder

Question #14

Reference: Exhibit 8/Tab 3/Schedule 2

Please provide the derivation of the forecast $41,000 in LV charges for 2010

CHE Response
Similarly to its projections for 2009, the LV Charges projections for 2010 were based on the historical information. CHE did projected higher LV charges for 2010 due to the growth projected for 2010.

Question #15

Reference: Exhibit 8/Tab 3/Schedule 3, Attachment 1

a) Please explain why it is reasonable to use a 5-year average for the loss factor calculation when the earliest year (2004) is materially higher than any of the subsequent years and Embrun has undertaken a number of actions in recent years (per Exhibit 8/Tab 3/Schedule 3, pages 2-3) to reduce system losses. Would an average of the four most recent years be more appropriate?

CHE Response
Please see CHE Response to Board Staff Interrogatories below.

8 LOSS FACTORS
Issue 8.1 System Loss Improvement Work
21 Ref: Exhibit(s) Exhibit 8 Tab 3 Schedule 3
Between 2006 and 2007, CHE improved its distribution system in an effort to reduce losses. This work was on the basis of the Utility Load Flow Study by Stantec Consulting Ltd. Distribution losses for 2006 - 2008 appear to be lower, as found on line G of Attachment A. What reasons would CHE have for not using the three year average for 2006-2008 rather than the five year average for distribution loss factors?

CHE Response
CHE was merely complying with the Board's direction at pages 22 of the minimum filing requirements when it opted to use a 5 year average. That being said, CHE agrees with the Board's logic that using a 3 year average is more accurate representation of the utilities losses. CHE's revised calculations are presented below. Also, CHE updated its rates and the resulting changes are reflected in the amended rate models filed in conjunction with the interrogatory responses.

	Losses in Distributor's System	2006	2007	2008	5 Year Average
A1	"Wholesale" kWh delivered to distributor (higher value)	-	-	-	
A2	"Wholesale" kWh delivered to distributor (lower value)	28,814,681.00	30,020,517.00	29,993,741.00	29,609,646.33

B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	-	-	-	
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)	28,814,681.00	30,020,517.00	29,993,741.00	29,609,646.33
D	"Retail" kWh delivered by distributor	28,275,060.00	29,064,673.00	29,483,564.00	28,941,099.00
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	-	-	-	
F	Net "Retail" kWh delivered by distributor (D)-(E)	28,275,060.00	29,064,673.00	29,483,564.00	28,941,099.00
G	Loss Factor in distributor's system [(C)/(F)]	1.0191	1.0329	1.0173	1.0231
	Losses Upstream of Distributor's System				
H	Supply Facility Loss Factor	1.034	1.034	1.034	1.034
	Total Losses				
I	Total Loss Factor [(G)x(H)]	1.0537	1.0680	1.0519	**1.0579**

Question #16

Reference: Exhibit 9/Tab 1/Schedule 1

a) Please report separately the history of the balance in i) Account 1588 – RSVA Power (excluding the Global Adjustment and ii) Account 1588 – RSVA Power – Global Adjustment Sub-account.

CHE Response
Please see table at the next page

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Cooperative Hydro Embrun	**LICENCE NUMBER**	ED-2002-0493
NAME OF CONTACT	Benoit Lamarche	**DOCID NUMBER**	EB-2009-0132
E-mail Address	embrunhydro@magma.ca		
VERSION NUMBER	v3.0	**PHONE NUMBER**	
Date	9-Dec-09	**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [6]	**Transactions (reductions) during 2005, excluding interest and adjustments** [6]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
RSVA - Wholesale Market Service Charge	1580	$ 44,160				$ 8,318	$ 52,478	$ 1,501	$ 973	$ 2,474
RSVA - One-time Wholesale Market Service	1582						$ -			$ -
RSVA - Retail Transmission Network Charge	1584	$ (24,961)				$ 255	$ (24,706)	$ (419)	$ (1,296)	$ (1,715)
RSVA - Retail Transmission Connection Charge	1586	$ 6,539				$ (2,206)	$ 4,333	$ (950)	$ (1,579)	$ (2,529)
Sub-Totals		$ 25,738	$ -		$ -	$ 6,367	$ 32,105	$ 132	$ (1,902)	$ (1,770)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$ 4,587	$ 4,587		$ 112	$ 112
Other Regulatory Assets - Sub-Account - Pension Contributions	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518						$ -			$ -
Retail Cost Variance Account - STR	1548						$ -			$ -
Misc. Deferred Debits	1525						$ -			$ -
LV Variance Account	1550						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Mete	1555						$ -			$ -
Smart Meter OM&A Variance	1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565					$ 9,928	$ 9,928			$ -
CDM Contra	1566					$ (9,928)	$ (9,928)			$ -
Qualifying Transition Costs [5]	1570		n/a	n/a			$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571		n/a	n/a			$ -			$ -
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ -	$ -	$ -	$ -	$ 4,587	$ 4,587	$ -	$ 112	$ 112
Deferred Payments in Lieu of Taxes	1562					**see PILs reconciliation requested**				
2006 PILs & Taxes Variance	1592					**see PILs reconciliation requested**				
Sub-Totals						**see PILs reconciliation requested**				
Total		$ 25,738	$ -	$ -	$ -	$ 10,954	$ 36,692	$ 132	$ (1,790)	$ (1,658)
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563					**see PILs reconciliation requested**				
RSVA - Power (including Global Adjustment)	1588	$ 67,966				$ 112,036	$ 180,002	$ 12,326	$ 12,119	$ 24,445
RSVA - Power - Sub-Account - Global Adjustment [4]	1598					$ 5,723	$ 5,723		$ 242	$ 242
Recovery of Regulatory Asset Balances	1590						$ -			$ -

C:\Users\mris-schofield\Documents\Embrun\IRs\MODELS\[Copy of 7_Continuity_Schedule_Board Staff_IR.xls]Continuity Schedule

1 As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
2 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
3 Provide supporting statement indicating nature of this adjustments and periods they relate to
4 Not included in sub-total
5 Closed April 30, 2002
6 For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
7 Please describe "other" components of 1508 and add more component lines if necessary.
8 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
9 Interest projected on December 31, 2008 closing principal balance.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Cooperative Hydro Embrun
NAME OF CONTACT	Benoit Lamarche
E-mail Address	embrunhydro@magma.ca
VERSION NUMBER	v3.0
Date	9-Dec-09

Account Description	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
RSVA - Wholesale Market Service Charge	1580	$ 52,478				$ (42,708)		$ 9,770	$ 2,474	$ 1,143		$ 3,617
RSVA - One-time Wholesale Market Service	1582	$ -						$ -	$ -			$ -
RSVA - Retail Transmission Network Charge	1584	$ (24,706)				$ (3,611)		$ (28,317)	$ (1,715)	$ (1,618)		$ (3,333)
RSVA - Retail Transmission Connection Charge	1586	$ 4,333				$ (40,744)		$ (36,411)	$ (2,529)	$ (2,113)		$ (4,642)
Sub-Totals		$ 32,105	$ -		$ -	$ (87,063)	$ -	$ (54,958)	$ (1,770)	$ (2,588)	$ -	$ (4,358)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 4,587				$ 1,328		$ 5,915	$ 112	$ 217		$ 329
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ -						$ -	$ -			$ -
Retail Cost Variance Account - STR	1548	$ -						$ -	$ -			$ -
Misc. Deferred Debits	1525	$ -						$ -	$ -			$ -
LV Variance Account	1550	$ -				$ 5,204		$ 5,204	$ -	$ 179		$ 179
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Mete	1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -				$ (3,381)		$ (3,381)	$ -	$ (52)		$ (52)
Conservation and Demand Management Expenditures and Recoveries	1565	$ 9,928				$ 957		$ 10,885	$ -			$ -
CDM Contra	1566	$ (9,928)				$ (957)		$ (10,885)	$ -			$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a				$ -	$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 4,587	$ -	$ -	$ -	$ 3,151	$ -	$ 7,738	$ 112	$ 344	$ -	$ 456
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested						
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested						
Sub-Totals						see PILs reconciliation requested						
Total		$ 36,692	$ -	$ -	$ -	$ (83,912)	$ -	$ (47,220)	$ (1,658)	$ (2,244)	$ -	$ (3,902)
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account [8]	1563					see PILs reconciliation requested						
RSVA - Power (including Global Adjustment)	1588	$ 180,002				$ (56,828)		$ 123,174	$ 24,445	$ 11,186		$ 35,631
RSVA - Power - Sub-Account - Global Adjustment [4]	1598	$ 5,723				$ 1,844		$ 7,567	$ 242	$ 506		$ 748
Recovery of Regulatory Asset Balances	1590	$ -						$ -	$ -			$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Cooperative Hydro Embrun
NAME OF CONTACT	Benoit Lamarche
E-mail Address	embrunhydro@magma.ca
VERSION NUMBER	v3.0
Date	9-Dec-09

		2007								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-07**	**Transactions (additions) during 2007, excluding interest and adjustments [6]**	**Transactions (reductions) during 2007, excluding interest and adjustments [6]**	**Adjustments during 2007 - instructed by Board [2]**	**Adjustments during 2007 - other [3]**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec31-07**	**Closing Interest Amounts as of Dec-31-07**
RSVA - Wholesale Market Service Charge	1580	$ 9,770				$ 1,905	$ 11,675	$ 3,617	$ (1,932)	$ 1,685
RSVA - One-time Wholesale Market Service	1582	$ -					$ -	$ -		$ -
RSVA - Retail Transmission Network Charge	1584	$ (28,317)				$ 14,822	$ (13,495)	$ (3,333)	$ 2,316	$ (1,017)
RSVA - Retail Transmission Connection Charge	1586	$ (36,411)				$ 11,713	$ (24,698)	$ (4,642)	$ 2,899	$ (1,743)
Sub-Totals		$ (54,958)	$ -		$ -	$ 28,440	$ (26,518)	$ (4,358)	$ 3,283	$ (1,075)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 5,915				$ (664)	$ 5,251	$ 329	$ 116	$ 445
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ -					$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ -					$ -	$ -		$ -
Misc. Deferred Debits	1525	$ -					$ -	$ -		$ -
LV Variance Account	1550	$ 5,204				$ 2,822	$ 8,026	$ 179	$ 279	$ 458
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Mete	1555	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ (3,381)				$ (5,994)	$ (9,375)	$ (52)	$ (294)	$ (346)
Conservation and Demand Management Expenditures and Recoveries	1565	$ 10,885					$ 10,885	$ -		$ -
CDM Contra	1566	$ (10,885)					$ (10,885)	$ -		$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Sub-Totals		$ 7,738	$ -	$ -	$ -	$ (3,836)	$ 3,902	$ 456	$ 101	$ 557
Deferred Payments in Lieu of Taxes	1562					**see PILs reconciliation requested**				
2006 PILs & Taxes Variance	1592					**see PILs reconciliation requested**				
Sub-Totals						**see PILs reconciliation requested**				
Total		$ (47,220)	$ -	$ -	$ -	$ 24,604	$ (22,616)	$ (3,902)	$ 3,384	$ (518)
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563					**see PILs reconciliation requested**				
RSVA - Power (including Global Adjustment)	1588	$ 123,174				$ (7,944)	$ 115,230	$ 35,631	$ (17,783)	$ 17,848
RSVA - Power - Sub-Account - Global Adjustment [4]	1598	$ 7,567				$ 779	$ 8,346	$ 748	$ 373	$ 1,121
Recovery of Regulatory Asset Balances	1590	$ -					$ -	$ -		$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Cooperative Hydro Embrun
NAME OF CONTACT	Benoit Lamarche
E-mail Address	embrunhydro@magma.ca
VERSION NUMBER	v3.0
Date	9-Dec-09

		2008								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-08**	**Transactions (additions) during 2008, excluding interest and adjustments [6]**	**Transactions (reductions) during 2008, excluding interest and adjustments [6]**	**Adjustments during 2008 - instructed by Board [2]**	**Adjustments during 2008 - other [3]**	**Closing Principal Balance as of Dec-31-08**	**Opening Interest Amounts as of Jan-1-08**	**Interest Jan-1 to Dec31-08**	**Closing Interest Amounts as of Dec-31-08**
RSVA - Wholesale Market Service Charge	1580	$ 11,675				$ (3,239)	$ 8,436	$ 1,685	$ 446	$ 2,131
RSVA - One-time Wholesale Market Service	1582	$ -					$ -	$ -		$ -
RSVA - Retail Transmission Network Charge	1584	$ (13,495)				$ (12,646)	$ (26,141)	$ (1,017)	$ (848)	$ (1,865)
RSVA - Retail Transmission Connection Charge	1586	$ (24,698)				$ (17,650)	$ (42,348)	$ (1,743)	$ (1,334)	$ (3,077)
Sub-Totals		$ (26,518)	$ -		$ -	$ (33,535)	$ (60,053)	$ (1,075)	$ (1,736)	$ (2,811)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 5,251					$ 5,251	$ 445	$ 113	$ 558
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ -					$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ -					$ -	$ -		$ -
Misc. Deferred Debits	1525	$ -					$ -	$ -		$ -
LV Variance Account	1550	$ 8,026				$ 2,704	$ 10,730	$ 458	$ 337	$ 795
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Mete	1555	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ (9,375)				$ (5,867)	$ (15,242)	$ (346)	$ (482)	$ (828)
Conservation and Demand Management Expenditures and Recoveries	1565	$ 10,885					$ 10,885	$ -		$ -
CDM Contra	1566	$ (10,885)					$ (10,885)	$ -		$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Sub-Totals		$ 3,902	$ -	$ -	$ -	$ (3,163)	$ 739	$ 557	$ (32)	$ 525
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested				
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested				
Sub-Totals						see PILs reconciliation requested				
Total		$ (22,616)	$ -	$ -	$ -	$ (36,698)	$ (59,314)	$ (518)	$ (1,768)	$ (2,286)
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563					see PILs reconciliation requested				
RSVA - Power (including Global Adjustment)	1588	$ 115,230				$ (36,218)	$ 79,012	$ 17,848	$ 4,800	$ 22,648
RSVA - Power - Sub-Account - Global Adjustment [4]	1598	$ 8,346				$ (1,171)	$ 7,175	$ 1,121	$ 313	$ 1,434
Recovery of Regulatory Asset Balances	1590	$ -					$ -	$ -		$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Cooperative Hydro Embrun
NAME OF CONTACT	Benoit Lamarche
E-mail Address	embrunhydro@magma.ca
VERSION NUMBER	v3.0
Date	9-Dec-09

Account Description	**Account Number**	**Projected Interest on Dec 31 -08 balance from Jan 1, 2009 to Dec 31, 2009** [9]	**Projected Interest on Dec 31 -08 balance from Jan 1, 2010 to April 30, 2010** [9]	**Claim before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2009 to Dec 31, 2009**	**Forecasted Transactions, Excluding Interest from Jan 1, 2010 to April 30, 2010**	**Projected Interest from Jan 1, 2009 to April 30, 2010 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to December 31, 2009**	**Projected Interest from Jan 1, 2010 to April 30, 2010 on Forecasted Transx (Excl Interest) from Jan 1, 2010 to April 30, 2010**	**Total Claim**
RSVA - Wholesale Market Service Charge	1580			$ 10,567	$ -	$ -	$ 28	$ 28	$ 10,623
RSVA - One-time Wholesale Market Service	1582			$ -		$ -			$ -
RSVA - Retail Transmission Network Charge	1584			$ (28,006)	$ -	$ -	$ (87)	$ (87)	$ (28,180)
RSVA - Retail Transmission Connection Charge	1586			$ (45,425)	$ -	$ -	$ (141)	$ (141)	$ (45,707)
						$ -			
Sub-Totals		$ -	$ -	$ (62,864)	$ -	$ -	$ (200)	$ (200)	$ (63,264)
						$ -			
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ 5,809	$ -	$ -	$ 18	$ 18	$ 5,845
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -		$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -		$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -		$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -		$ -			$ -
Retail Cost Variance Account - Retail	1518			$ -		$ -			$ -
Retail Cost Variance Account - STR	1548			$ -		$ -			$ -
Misc. Deferred Debits	1525			$ -		$ -			$ -
LV Variance Account	1550			$ 11,525	$ -	$ -	$ 36	$ 36	$ 11,597
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555			$ -		$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555			$ -		$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Mete	1555			$ -		$ -			$ -
Smart Meter OM&A Variance	1556			$ (16,070)	$ -	$ -	$ (51)	$ (51)	$ (16,172)
Conservation and Demand Management Expenditures and Recoveries	1565			$ 10,885	$ -	$ -			$ 10,885
CDM Contra	1566			$ (10,885)	$ -	$ -			$ (10,885)
Qualifying Transition Costs [5]	1570			$ -					$ -
Pre-Market Opening Energy Variances Total [5]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ -					$ -
Deferred Rate Impact Amounts	1574			$ -					$ -
Other Deferred Credits	2425			$ -					$ -
Sub-Totals		$ -	$ -	$ 1,264	$ -	$ -	$ 3	$ 3	$ 1,270
Deferred Payments in Lieu of Taxes	1562								
2006 PILs & Taxes Variance	1592								
Sub-Totals				$ -					$ -
Total		$ -	$ -	$ (61,600)	$ -	$ -	$ (197)	$ (197)	$ (61,994)
The following is not included in the total claim but is included on a memo basis:									
Deferred PILs Contra Account [8]	1563								
RSVA - Power (including Global Adjustment)	1588			$ 101,660					$ 101,660
RSVA - Power - Sub-Account - Global Adjustment [4]	1598			$ 8,609			$ 48	$ 48	$ 8,705
Recovery of Regulatory Asset Balances	1590			$ -			$ 527	$ 527	$ 1,054

C:\Users\mris-schofield\Documents\Embrun\IRs\MODELS\[Copy of 7_Continuity_Schedule_Board Staff_IR.xls]Continuity Schedule

b) Please re-calculate the proposed rate riders using the cost allocation factors directed by the Board in its EB-2008-0046 Report (page 21) for the two accounts referenced in part (a). Manuela

CHE Response
Please see CHE related responses to Board Staff Interrogatories copied below.

Issue 10.3 Account 1588

27 Ref: Exhibit(s) Exhibit 9 Tab 1 Schedule 1 Attachment 1
On October 15, 2009, the Board's Regulatory Audit & Accounting group issued a bulletin related to Regulatory Accounting & Reporting of Account 1588 RSVA Power and Account 1588 RSVA Power Sub-account Global Adjustment. Please confirm whether or not CHE plans on making any changes to its filing with respect to Account 1588.

Preamble: the following is an e-mail from the OEB providing guidelines on the treatment of the disposition of the balance in Account 1588-RSVA Power sub-account Global Adjustment

"The Board's accounting policies and procedures for the global adjustment (GA) sub-account 1588 are clear in that this account balance is attributable to non-Regulated Price Plan ("RPP") customers only. The Accounting Procedures Handbook (APH) in Articles 220 (page 36) and 490 (pages 21-22) specify that Account 1588, RSVAPower, "Sub-account Global Adjustment", is established for the purpose of recording the "net difference" in the global adjustment attributable to non- RPP customers only.

For the purposes of the disposition of the sub-account balance in rates, the "Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)" EB-2008-0046, specify that the default cost allocation methodology for the "Sub-account Global Adjustment" would be on kWh basis for non-RPP customers. In terms of the rate design, the distributor may consider a few options when requesting disposition of the balance in a cost of service application. Some options are outlined below.

1. Use the existing deferral and variance rate rider, where the account balance is recovered from /refunded to all Customers in all Rate Classes

2. Use a new and separate variance account rate rider, where the account balance is recovered from /refunded to all Non-RPP Customers only in all Rate Classes

Option 1 allocates the GA sub-account balance to only Non-RPP customers in all customer classes to derive the rate rider. Under this approach however, although the GA is allocated to only Non-RPP customers, all customers (RPP and Non-RPP) will be charged/refunded for the GA amount in the rate rider. The reason for this is that the allocated GA amounts to Non-RPP customers are combined with all other account disposition amounts to derive the rate rider, which does not distinguish Non-RPP from RPP customers. Therefore, a distributor will need to assess the impacts as to whether this approach would pose any material unfairness by including the RPP customers. The onus would be the distributor to make this assessment. The distributor should consider option 2 (below) if this approach is considered inappropriate.

Option 2 is the same as option 1, except that is new and separate rate rider is used. This approach is purer in that it assigns direct cost responsibility associated with the GA account *balance to only Non-RPP customers. The determination of the derived GA amount for Non-RPP customers only in each class is done on the same basis as discussed above. However, the Non-RPP allocated amounts for each class are included in a separate rate rider calculation sheet to derive a charge/refund amount for Non-RPP customers only in each class under a new and separate rate rider. The merits for having a separate rate rider could be considered in the context of assigning direct cost responsibility to non-RPP customers only.*

Lastly, I suggest that a distributor will need to assess it own customer base (RPP and Non-RPP), classes, billing system, customer relations, etc. in order to make a determination for selecting an option. The distributor should be able to justify its methodology for clearing the GA account balance in rates, be it under one of the options I have identified, or some other method"

Based on the direction provide by the OEB. CHE created a materiality analysis based on both options listed above. The materiality analysis can be found at the following page. Upon review of the bill impact for both options, CHE determined that the best option for their utility was the first option; namely that all customers (RPP and Non-RPP) will be charged/refunded for the GA amount in the rate rider.

CHE proposes to amend their model to reflect these changes. The models will be provided when required or requested by the board

Materiality Analysis on Global Adjustment rate rider

Estimated non-RPP kWh's in 2010

	2010 kWh's	% kWh's non-RPP	2010 non-RPP kWh's	Allocation Factor
Residential	19,657,452	8.68%	1,707,030	70.34%
GS < 50 kW	4,976,291	3.69%	183,458	7.56%
GS > 50 kW	4,387,835	12.22%	536,345	22.10%
USL	93,536			
Street Lighting	388,274			
Total	29,503,388		2,426,834	100.00%

GA sub-acct balance as at Dec 31/08

Principal	7,175			
Interest	21			
Total	7,196			
Interest to Apr 1/2010		158	rate:	0.55%
Disposition Amount		7,196		

Option 1: Rate rider for all customers

	Balance Allocation (a)	2010 kWh's/kW's (b)	Rate Rider (a)/(b)
Residential	5,062	19,657,452	$0.0003
GS < 50 kW	544	4,976,291	$0.0001
GS > 50 kW	1,590	12,779	$0.1245
USL			
Street Lighting			
TOTAL	7,196	24,646,522	

Option 2: Distinct rate rider

	Balance Allocation (a)	2010 kWh's (b)	Rate Rider (a)/(b)
Residential	5,062	1,707,030	$0.0030
GS < 50 kW	544	183,458	$0.0030
GS > 50 kW	1,590	536,345	$0.0030
USL	0	0	
Street Lighting	0	0	
TOTAL	7,196	2,426,834	

Average Bil Impact

	# Customers	Avg. monthly kWh's / kW's	Option 1 Charge	Option 2 Charge
Residential	1,834	893	$0.23	$2.65
GS < 50 kW	162	2,560	$0.28	$7.59
GS > 50 kW	12	89	$11.04	$0.26
USL	20	0		
Street Lighting	407	0		

	Total Bill 2010		Option 1 Impact	Option 2 Impact
Residential	$100.25		0.2%	2.6%
GS < 50 kW	$286.40		0.1%	2.7%
GS > 50 kW	$3,435.25		0.3%	0.0%

Issue 10.4 Rate Rider Calculation

28 Ref: Exhibit(s) Exhibit 9 Tab 2 Schedule 1 Attachment 2
Board staff has reviewed the determination of the proposed rate riders for conformance to Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative, EB-2008-0046, July 31, 2009.

a. Please explain why CHE is allocating Account 1550 LV Variance Account on the basis of transmission connection revenue rather than class kWh?

CHE Response:
CHE allocated the account balance based on transmission connection revenue in accordance with the practice in effect at the time the rate application was prepared. CHE agrees to modify the allocation on the basis of class kWh's. The resulting changes are reflected in the amended rate models filed in conjunction with the interrogatory responses.

b. Please explain why CHE has determined the unit rate based on forecasted volumes rather than the most recent Board-approved volumes?

CHE Response:
CHE submits that the proposed forecasted volumes are more likely to ensure the intended dispositions are achieved, and will in fact constitute the most recent Board-approved volumes at the time the rate riders come into effect. CHE proposes to amend the forecasted volumes to the extent any changes are made to the forecast approved in the Board's decision on this rate application.