Coopérative Hydro Embrun Inc.

November 3, 2017
Ontario Energy Board P.O.
Box 2319 27th Floor
2300 Yonge Street Toronto,
Ontario M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary
Regarding: EB-2017-0035-2018 Cost of Service Application

Dear Ms. Walli,

Please find attached Cooperative Hydro Embrun Inc's 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 OEB Staff Interrogatories
2018 Cost of Service Rate Application
Cooperative Hydro Embrun Inc. (Cooperative Hydro Embrun)
EB-2017-0035
November 3, 2017

Contents

Updates to the models

1.	RateModel:	2-Staff-16	Update Cost of Power in tab 4.12
2.	RateModel:	3-Staff-30	Update to Revenue Offsets MicroFit
3.	RTSR:	8-Staff-59	Update model to 2018
4.	Load Fcast:	3-Staff-25	Formula error in B42 (Bridge&Test Forecast)
5.	Load Fcast	3-Staff-26	Missing kWh adj. for Street Lighting
6.	Load Fcast	3.0 –VECC -21	Add verified 2016 results
7.	LRAMVA.	4-Staff-42	New model and update threshold 388,471
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10.	RRWF:	7-Staff-49	Revenue to Cost Ratio
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13.	CA:	7-Staff-55	I7.1/I7.2 meters don't match customer count
14.	DVA CS:	Exhibit 9 – Deferral and Variance Accounts	

Updated Models & Documents filed.

1. CHEI 2018 LRAMVA Work Form
2. CHEI DVA Continuity Schedule
3. CHEI Update of Demand Data
4. CHEI Load Forecast model
5. CHEI Tariff Schedule and Bill Impacts
6. CHEI RTSR Workform
7. CHEI Rev Reqt Work Form
8. CHEI PILs Workform
9. CHEI Cost Allocation
10. CHEI GA Work Form
11. 2011-2014 Verified Results
12. 2016 Verified Results

13. CDM Approved Plan
14. CHEI Ch2 Appendices

Preamble – 2017 Budgeted vs. 2017 Actual (9mon Actual+3mon Budgeted)

CAPITAL

As a May 1 filer, CHEI used 12 months of budgets in its application filed on May 1, 2017. As requested in the IRs, CHEI has provided in the table below a comparison of its 2017 budgeted as per submitted on May 1, to its “To date” as of the end of September 2017 and its year-end budgets using January – September as actuals and October to December as budgeted.

System Access	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)	Notes
New O/H -U/G Services	1855	$20,000.00	$18,612.35	$20,000.00	
Centenaire/Mr. Desforges	1855	$0.00	$14,500.00	$14,500.00	New development
St-Malo / Devcore	1855	$0.00	$20,500.00	$20,500.00	
Meters	1860	$8,000.00	$14,717.00	$15,500.00	Order Special Meters (Networks 120/208)to accommodate 31 units - Condo Building
Sub-Total		**$28,000.00**	**$68,329.35**	**$70,500.00**	
Versailles III Project	1850	$20,675.00	$0.00	$0.00	Postponed to 2018
Versailles III Project	1845	$160,025.00	$0.00	$0.00	Postponed in 2018
Centenaire/Mr. Desforges	1850	$0.00	$5,195.00	$5,195.00	
St-Malo / Devcore	1850	$0.00	$5,195.00	$5,195.00	
Dagenais Building	1850	$0.00	$0.00	$10,000.00	
Sub-Total		**$180,700.00**	**$10,390.00**	**$20,390.00**	
New Substation	1820	$1,487,396.00	$723,575.00	$1,487,396.00	
Engineer	1820	$30,000.00	$0.00	$30,000.00	
Sub-Total		**$1,517,396.00**	**$723,575.00**	**$1,517,396.00**	
System Access Total		**$1,726,096.00**	**$802,294.35**	**$1,608,286.00**	

System Renewal	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)	Notes
System Renewal		**Forecast**	**Actual**	**Year-end**	
Transformers Program	1850	$20,000.00	$0.00	$20,000.00	
(Elbows and Inserts					

System Renewal Total		**$20,000.00**	**$0.00**	**$20,000.00**	

System Access	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)	Notes
System Service		**Forecast**	**Actual**	**Year-end**	
Four Way Tie in Switch	1835	$39,650.00	$39,650.00	$39,650.00	
336 MCM Conductors	1835	$46,250.00	$50,683.00	$50,683.00	
Blais Street					
System Service Total		**$85,900.00**	**$90,333.00**	**$90,333.00**	

System Access	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)	Notes
General Plant		**Forecast**	**Actual**	**Year-end**	
Website	1611	$3,000.00	$2,945.00	$2,945.00	
Antivirus	1611	$1,500.00	$285.00	$500.00	
Office Equipment	1915	$1,000.00	$0.00	$1,000.00	
Computer and Hardware	1920	$1,500.00	$565.00	$1,500.00	
Upgrade Harris CIS System	1611	$0.00	$6,771.00	$6,771.00	Upgrade done after filing
General Plant Total		**$7,000.00**	**$10,566.00**	**$12,716.00**	

OM&A

Operation	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)
	5012	$1,380	$1,220	$1,220
Transformer Maintenance	5035	$3,350	$2,969	$3,500
Meter Maintenance	5065	$1,200	$1,175	$1,200
Locate	5075	$20,400	$15,355	$20,400
Petty Cash, Gift Employees & Directors	5085	$9,500	$6,585	$8,500
Sub Total		**$35,830**	**$27,304**	**$34,820**

Maintenance	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)
UniFirst - $1000	5110	$9,000	$5,929	$8,500
Office Cleaning $4000				
Electricity$4000				
Inspection Bi-Annual $1200	5114	$6,450	$3,973	$6,100
Snow Removal $1000				
Electricity $2300				
General Maintenance $1950				
Overhead Maintenance /Pole	5120	$6,985	$5,492	$6,985
Overhead Maintenance /Device	5125	$5,690	$3,441	$5,690
Tree Trimming (wind storms)	5135	$8,000	$12,144	$12,144
U/G Maintenance Conductors &Devices	5150	$10,420	$8,069	$10,000
U/G Maintenance Customer Services	5155	$2,100	$1,800	$2,000
Maintenance Line Transformer	5160	$2,000	$696	$1,800
Sub Total		**$50,645**	**$41,544**	**$53,219**

Billing and Collecting	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)
Customer Billing	5315	$183,718	$120,551	$183,000
Collection Charges	5330	$4,305	$1,967	$3,200
Bad Debt Expenses	5335	$10,000	$5,000	$7,500
Sub Total		**$198,023**	**$127,518**	**$193,700**

Community	USoA Account	Forecast for May 1 CoS	Jan-Sept (9)	Projected Year End (9+3)

Community Relations	5410	$4,500	$4,285	$4,500
Advertising Expenses	5515	$3,000	$1,984	$3,000
Sub Total		**$7,500**	**$6,269**	**$7,500**

Administration	**USoA Account**	**Forecast for May 1 CoS**	**Jan-Sept (9)**	**Projected Year End (9+3)**
Executive Salaries and Expenses	5605	$33,600	$28,135	$33,600
Management Salaries and Expenses	5610	$100,289	$69,000	$100,289
General Administrative Salaries and Expenses	5615	$69,000	$54,285	$69,000
Office Supplies and Expenses	5620	$39,294	$32,472	$39,000
Outside Services Employed	5630	$47,325	$41,891	$47,000
Property Insurance	5635	$4,200	$1,856	$1,856
Injuries and Damages	5640	$3,440	$3,184	$3,184
Regulatory Expenses (community meeting print)	5655	$43,500	$34,599	$45,500
Rent	5670	$15,000	$12,500	$15,000
Electrical Safety Authority Fees	5680	$1,970	$1,898	$1,898
Donation	6205	$2,500	$1,480	$2,500
Leap Funding	6205	$2,000	$2,000	$2,000
Sub Total		**$362,118**	**$283,300**	**$360,827**

Total		**$654,116**	**$485,935**	**$650,066**
				-$4,050

Exhibit 1 – Administration

1-Staff-1

Responses to Letters of Comment

At the community meeting, two consumers provided comments regarding Cooperative Hydro Embrun's application.

Section 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments received at the community meetings, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

The letter from Mr. Roy expressed concern that increases appear to be disproportionately absorbed by the residential class, while the commercial bill impacts show a decrease. CHEI notes that the relative bill impacts shown in this application result from the cost allocation model completed in accordance with OEB policy. Specifically, the relative adjustments to the residential and GS>50kW rate classes reflect the OEB expectation that the revenues from rate classes will reflect, to the extent possible, the cost of the services provided to the rate class. In CHEI's case, the results of the cost allocation study indicate that existing rates for the GS>50kW rate class have been recovering revenues slightly in excess of costs incurred, and have therefore been providing a small subsidy to the other rate classes. The proposed revenue to cost ratios are intended to address this cross-subsidization.

The letter from Mr. Carriere appears to express dissatisfaction with the cost of the community meeting. CHEI notes that the community meeting is held in response to a requirement by the OEB, and is beyond CHEI's control.

CHEI commits to providing a personal response letters to Mr. Paul Roy and Mr. Pierre Carrière before the argument phase of this proceeding.

1-Staff-2

Ref: Exhibit 1/Business Plan/Section 2.2/Page 6 - Utility Ownership

Cooperative Hydro Embrun is structured as a cooperative utility under the *Cooperative Corporations Act,* and is based on voluntary and open membership with a one-time cost of $10 per member. Each customer is a member and owner of the business with an equal say in decision making. Profits are either reinvested for infrastructure or distributed to members in the form of dividends.

(a) Can one member own multiple shares?
(b) At its Corporate Annual Meeting, please explain how (i.e. in what format) members views are heard in relation to the Cooperative's proposed plans.
(c) Please provide any meeting minutes or reports as available.
(d) Please describe in detail what types of decision making Cooperative Hydro Embrun's members actively participate in? In the discussion, please explain if members participate in the decision making on specific capital and OM&A programs to undertake.
(e) Please describe the system used in decision making.

Response:

(a) No, they cannot. A member can only have one share.
(b) The annual meeting is held once a year. A copy of the Annual Report 2016 was provided at Appendix F page 72 of Exhibit 1- Administrative Documents. The adoption of the agenda of the meeting is moved and seconded by a member. The meeting covers two main items. The President's Message and General Manager's Report. The President's Message includes financial results for the past year and the coming year project. The General Manager explains the significant developments in the past year and plans for the upcoming year. The meeting concludes with a question period. The meeting had a similar format as the OEBs Community Meeting where the utility's capital plan and operational plan was presented. The customers were encouraged to ask questions and provide thoughts and feedback on the utility's proposed costs. The utility also encourages its customers to call and stop by the office to raise any concerns or ask any questions.
(c) A copy of the Annual Report 2016 was provided at Appendix F page 72 of Exhibit 1- Administrative Documents.
(d) Capital and OM&A budgets are explained during the auditor's presentation of the financial statement. Again, the members can question the proposed budgets

during a question period. Following the questions period, a resolution from the members is adopted by way of vote.

(e) The decision making is done by way of vote and resolution (Moved by and Seconded by Resolution). Unlike most other utilities, CHEI is a member organization. This means that while members of the board of directors have the same duties and responsibilities as do board members of any other utility, the also have a few other responsibilities that are unique to cooperative board members. This places a unique responsibility on cooperative directors to be sensitive to the needs of members which are both shareholder and customers. Therefore, director decisions are based not only on what is most profitable in terms of dividends but also on what the needs and wants of the members are. One important function of the cooperative board is to educate members about their organization and continuous plans. As communicated in the Business Plan, the customer engagement is not always done formally but is often done informally at the bank or grocery store. The utility also holds a Board of Director meeting every month where the budgets and plans and priorities are presented, discussed and decided. CHEI notes that the prioritization process is explained in detail in section 3.3. [5.3.3] Asset Lifecycle Optimization Policies and Practices of the DSP.

1-Staff-3

Ref: Exhibit 1/Business Plan/Section 4.3/Page 10 – Alignment of Goals to Needs and Preferences of Customers

In advance of this application, Cooperative Hydro Embrun notes that it reached out to customers to seek feedback on their views and preferences. Based on this feedback, Cooperative Hydro Embrun is confident that with the communication plan in place, the utility's capital budget supports customer's preferences and priorities.

(a) Please elaborate on the "communication plan in place".
(b) Please provide examples on what type of feedback made Cooperative Hydro Embrun confident about its proposed capital expenditures.
(c) Please provide examples on any of the feedback that supports the proposed OM&A spending for the test year.

Response:

(a) Please see pages 8-9 of the Business Plan for a description of the communication plan. CHEI employs news releases, bill inserts, social media and information letters by email, as well as its Annual General Meeting to inform its customers and to seek feedback.
(b) Please see section 4.2 of the Business Plan. The utility published a summary of its proposed capital expenditures for 2017 and 2018 via a press release, website update, info letter, Twitter and in person at an annual meeting and again at the OEB's community meeting. The utility has given its customers ample notice and opportunity to weigh in on its proposed capital spending. CHEI received no negative feedback from its customers as a result of this outreach. In the absence of contrary feedback, CHEI has assumed that its proposed capital plan is acceptable to its customers.
(c) While the utility's customer engagement activities focused more on the capital spending, especially the investment in a substation and asset replacement, the utility also presented its OM&A costs during the Annual Meeting and received no negative feedback. The utility presented its OM&A as part of the OEB's Community Meeting and received one question regarding salaries. The response given by CHEI's management appeared to satisfy the customer in question.

1-Staff-4

Ref 1: Exhibit 1/Business Plan/Section 5.1/Page 14 – Past Performance
Ref 2: 2018 Benchmarking Model (PEG)

Table 2 of reference 1 is reproduced below:

	2014 (History)	2015 (History)	2016 (History)
Cost Benchmarking Summary			
Actual Total Cost	1,052,237	1,097,457	1,119,904
Predicted Total Cost	1,415,586	1,530,324	1,802,737
Difference	(363,350)	(432,867)	(682,833)
Percentage Difference (Cost Performance)	-29.7	-33.2%	-47.6%
Stretch Factor Cohort - Annual Result	2	1	1

At reference 2, the “Results” tab shows that for 2016 the percentage difference (cost performance) is -25% as opposed to the -47.6% result in the table above.

Please explain the apparent discrepancy.

Response: Please find below the corrected PEG Benchmarking Results used in the Business Plan. CHEI notes that it also corrected an input error at Tab “Model Input” cells H15/I15/J15 where the utility used the yearly total demand rather than the Annual Peak Demand. CHEI used the verified Peak Demand from the 2016 Yearbook and escalated 2017 and 2018 using the demand from the Load Forecast.

		2015	2016	2017	2018
		(History)	(Bridge)	(Test Year)	
Cost Benchmarking Summary					
Actual Total Cost		1,097,457	1,119,145	1,164,307	1,173,602
Predicted Total Cost		1,530,324	1,629,366	1,752,729	1,790,228
Difference		(432,867)	(510,221)	(588,422)	(616,626)
Percentage Difference (Cost Performance)		**-33.2%**	**-37.6%**	**-40.9%**	**-42.23%**
Three-Year Average Performance				-37.2%	-40.23%
Stretch Factor Cohort					
	Annual Result	1	1	1	1
	Three Year Average			1	

1-Staff-5

Ref 1: Exhibit 1/Business Plan/Section 8/Page 28 – Financial Results
Ref 2: Exhibit 1/Section 1.10/Page 60 – Financial Information

Financial Ratios

	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	Profitability (Approved ROE)	Regulatory Return on Equity (Achieved ROE)
2011	3.19	0	9.36%	6.26%
2012	3.24	0	9.36%	10.28%
2013	3.14	0	9.36%	8.43%
2014	3.09	0	9.36%	4.35%
2015	2.87		9.36%	1.53%

Cooperative Hydro Embrun notes that its financial performance has remained strong over the past 4 years. By the end of 2017, Cooperative Hydro Embrun will be under-earning mainly due to increases in capital spending and a one-time administrative cost associated with an OEB audit.

Please explain the causes of the significant under-earning in 2014 and 2015 and indicate the amount and provide explanation of any one-time events such as those experienced in 2017 which impacted the achieved ROE.

Response:

The rate of return included in the utility's rates is based on a snapshot of the utility's Rate Base in its Board Approved Test Year (2014). CHEI has continued to actively modernize and enhance its infrastructure thereby increasing its Rate Base. Under the current five-year rate cycle, a utility does not see an immediate increase in revenue when it develops capital goods. CHEI, therefore, considers it normal for its Return on Equity to deteriorate as its Rate Base increases and its revenues remain static. Specific OM&A Cost Drivers which would have contributed to the deterioration of the ROE are addressed on Page 9 of Exhibit 4.

1-Staff-6

Ref: Exhibit 1/Section 1.3.4/Page 10 – Legal Application

At the above reference, it is noted that "this application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated January 2, 2014."

Please confirm that the above is a typographical error and Cooperative Hydro Embrun followed the OEB's most recent Filing Guidelines applicable at the time of filing (i.e. 2016 edition for 2017 rate applications issued July 14, 2016).

Response:

Confirmed. The reference should have pointed to the July 14, 2016, Filing Guidelines.

1-Staff-7

Customer Engagement
Ref: Chapter 2 of the Filing Requirements, Section 2.1.6

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement. Please explain how customer engagement has been enhanced.

Response:
In early 2016, CHEI started discussing and implementing Customer Engagement ideas in advance of its upcoming 2018 Cost of Service. The resulting customer engagement plan is significantly more extensive than efforts made in prior years.

CHEI's customer engagement started in the Spring of 2016 when it updated its Conditions of Service. During the Summer of 2016, the utility decided to revamp its website to accommodate several new Customer Engagement ideas. The first of these was an "Electricity 101" section, which explains various aspects of the industry including the rate process. The utility also added a new section on its website which details its capital projects.

In the Fall of 2016, the utility hired Stantec to start documenting the need for a new Substation. CHEI also engaged AESI to develop its Distribution System Plan. Following the release of the OEB's Rates Handbook in October of 2016, the utility started working on its Business Plan which details the utility's Cost of Service specific communication plan. The utility plans to post its final Business Plan on its website once the OEB's final decision is issued.

In April 2017 CHE informed the customers by way of bill insert, newsletter, website, e-billing message, Facebook Twitter, and newspaper a message ¨What you need to know¨ explaining the 2017-2018 capital expenditures. The General Manager also made a presentation at the annual meeting to explain its capital and OM&A expenditures.

On September 19, 2017, the OEB invited the customers of CHEI to "have their say" about the application. The OEB used the newspaper to invite customers, and CHEI sent the invitation by mail, twitter, Facebook, website, and newsletter.

1-Staff-8

Reflecting Customer Needs
Ref: Chapter 2 of the Filing Requirements

Chapter 2 of the Filing Requirements states, "Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e., costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application".

What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

Response:
Please see the response to Interrogatory 1-Staff-3.

1-Staff-9

Customer Satisfaction Survey
Ref: Exhibit 1/Section 1.7.2/Pages 52-54

Cooperative Hydro Embrun, through a collaborative effort with Hearst Power Distribution Company Limited, Hydro Hawkesbury Inc., Hydro 2000 Inc., and Chapleau Public Utilities, developed an in-house customer satisfaction survey in order to minimize the cost of the survey and to share intellect and resources.

(a) Please indicate the number of respondents to the survey specific to Cooperative Hydro Embrun.
(b) Does Cooperative Hydro Embrun find the response rates acceptable as a basis for measuring customer satisfaction? If so, why?
(c) How much weight did Cooperative Hydro Embrun give to the customer preferences identified in setting priorities for investment?
(d) What steps does Cooperative Hydro Embrun intend to undertake to improve the information regarding customer views of Cooperative Hydro Embrun's performance. In your response, please address actions taken for commercial customers as well as other customers.

Response:

(a) The information requested is presented at Exhibit 1, page 53 line 14
(b) The information requested is presented at Exhibit 1, page 53 line 8 to 11
(c) Wherever feasible, CHEI will consider members preferences as discussed in earlier responses and cite the responses. Please see response to 1-Staff-3 for details on Alignment of Goals to Needs and Preferences of Customers
(d) In compliance with the OEB's policies and requirements, the utility intends to conduct its survey on a bi-annual basis. As explained in the SWOT section of the Business Plan, as a small utility, customer engagement is most often done informally outside of the utility or in person at the utility's offices. With respect to the commercial customers, the utility has modified its survey for the customer class and intends to conduct the survey between the bi-annual residential survey. The commercial survey is scheduled for 2018.

1-Staff-10

Ref 1: Exhibit 1/Section 1.7.2/Pages 52-54 – Customer Satisfaction Survey
Ref 2: Exhibit 1/Section 1.7.1/Page 49 – Overview of Customer Engagement

At reference 1, Cooperative Hydro Embrun discusses the results of a customer satisfaction survey. OEB staff notes that while a customer satisfaction survey is a good tool to gauge how a customer views the past performance of its utility, it is not necessarily a tool that engages customers on future plans.

(a) Did the survey contain data comparisons to an Ontario-wide LDC benchmark?
(b) Did the survey results help shape certain parts of Cooperative Hydro Embrun's current application? If yes, please explain what was adopted in this application as a direct result of the survey completed by customers.
(c) Did Cooperative Hydro Embrun conduct any benchmarking to support the current cost of service application?

At reference 2, Cooperative Hydro Embrun notes that it hosted a town hall meeting to discuss the 2017 and 2018 capital budget. Fifty customers attended the meeting, and none of the attendees provided feedback on the proposed capital spending.

(d) Does Cooperative Hydro Embrun find the attendance rates acceptable as a basis for measuring customer wants? If so, why?
(e) Did Cooperative Hydro Embrun discuss its proposed OM&A budget and any specific programs related to OM&A? If yes, please provide a description. If not, please explain why.
(f) Please provide a copy of the presentation made to customers at the town hall meeting.

Response:

(a) The survey conducted did not include any Ontario Wide LDC benchmark information.
(b) Please see CHEI's response to 1-Staff-9 c)
(c) As a small utility with limited resources, CHEI relies upon the OEB's PEG Benchmarking study and the Yearbook.
(d) As explained in the Business Plan, the utility used every media blast available to communicate its capital spending plan to its customers (in-person, newsletter, social media, website, bill insert…) Details regarding capital projects are also posted on the utility's website. CHEI notes that an attendance figure of 50 customers out of a total of 2,155 is consistent with attendance figures for OEB community meetings.

(e) Please see the response to interrogatory 1-Staff-3.
(f) No specific slideshow was prepared. Instead, the utility showed and discussed the Newsletter presented at Appendix F of Exhibit 1. The utility also used the OM&A tabs from the OEB's Chapter 2 Appendices to discuss the OM&A expenses.

1-Staff-11

Ref: Exhibit 1/Section 1.5/Page 31 – Application Summary

Cooperative Hydro Embrun indicates that OM&A cost expenditures for the 2018 test year are the result of a planning and work prioritization process that ensures that the most appropriate cost-effective solutions are put in place.

Please explain what type of criteria or strategy is used to determine which solutions are the most cost-effective for Cooperative Hydro Embrun and its customers.

Response:

Capital:

The prioritization process is explained in detail in section 3.3.[5.3.3] Asset Lifecycle Optimization Policies and Practices of the DSP.

Business Plan page 10: CHEI's priority for 2017-2018 is to make sure that the current transformer does not exceed its capacity and that the construction of the new 44KV is done on time and on budget so that the utility can provide electricity to its customers in a reliable and responsible manner. Other priorities involve maintenance of its poles and meters at a steady pace to minimize rate shock.

OM&A

Details on the budgeting process are detailed in Section 1.5 of Exhibit 1, specifically page 31 of 77.

In addition, CHEI notes that the utility's practice for the Board of Director is to find the most reliable and cost-effective solution available. The Manager reviews all OM&A expenses monthly and explores whether more cost-effective options are available. CHEI's approach to cost management is that the utility will operate within the confines of its approved revenue requirement as much as possible.

1.0-VECC-1

Reference: Exhibit 1/pg.62

a) Please provide Embrun's 2016 scorecard results.

Response:

The 2016 Scorecard is presented at the next page.

Scorecard - Cooperative Hydro Embrun Inc.

8/17/2017

Performance Outcomes	Performance Categories	Measures		2012	2013	2014	2015	2016	Trend	Target	
										Industry	Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	90.50%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		96.00%	97.00%	97.60%	92.80%	95.20%		65.00%	
	Customer Satisfaction	First Contact Resolution				92%	92%	95%			
		Billing Accuracy				99.98%	99.30%	99.74%		98.00%	
		Customer Satisfaction Survey Results				90%	90%	85.89			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness					75.00%	75.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.08	0.04	0.01	0.03	0.04			1.83
		Average Number of Times that Power to a Customer is Interrupted [2]		0.02	0.02	0.13	0.01	0.23			0.64
	Asset Management	Distribution System Plan Implementation Progress				In Progress	In Progress	Completed			
	Cost Control	Efficiency Assessment		2	2	2	1	1			
		Total Cost per Customer [3]		$532	$568	$530	$533	$521			
		Total Cost per Km of Line [3]		$38,571	$39,819	$31,886	$30,485	$32,721			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]					6.73%	48.63%			1.79 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time			100.00%	100.00%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		3.24	3.14	3.09	2.87	2.65			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.00	0.00	0.00	0.00	0.00			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.85%	9.36%	9.36%	9.36%	9.36%			
			Achieved	10.28%	8.43%	4.35%	1.53%	3.68%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

1.0-VECC-2

Reference: Exhibit 1/Appendix D

a) Please identify the author of the customer survey at Appendix D.
b) What was the cost of this survey?

Response:

(a) The authors(s) of the survey and further modifications to the 2016 survey are discussed in Section 1.7.2 of Exhibit 1.
(b) There were no costs associated with conducting the survey.

Exhibit 2 – Rate Base

2-Staff-12

Ref: Exhibit 2/Section 2.1.2/Page 8 – Rate Base Trend

Cooperative Hydro Embrun's rate base for the 2018 test year is forecast to increase significantly by approximately 62% from the 2014 OEB-approved amount.

(a) In its annual capital planning and implementation for the years 2014 to 2018, how did Cooperative Hydro Embrun take into account the cumulative impact its capital expenditures would have on rate base and rates in 2018 given the large increase?

(b) How did this inform the pacing of investments identified in the Distribution System Plan for 2018 forward?

Response:

(a) Without the building of the substation in 2017, the increase between 2014 and 2018 would have been 15%. Therefore, the only significant contributor to the 62% increase between 2014 and 2018 is the capital work necessary to accommodate the new Substation. CHEI feels that the need for the substation was well explained and justified in the DSP.

(b) As explained above as well as in several sections of the application including the Business Plan, Exhibit 2 and the DSP, the Substation is the main contributor to the capital increase. CHEI believes there is no pacing a $1.5M substation. There is only sound and prudent planning and communication. CHEI notes that the need for a substation was addressed in its 2014 Cost of Service Application where CHEI clearly indicated that the priority at the time was to build a 4th feeder on Ste-Thérèse St, Cloutier, Sainte-Marie Road and Notre-Dame Street.

Most, if not all the capital work performed by the utility would be described as non-discretionary or necessary to the continuity of service and reliability. Therefore, there is little to no room for pacing. That said, CHEI is always mindful of the effect of large capital investments on rates. To the best of its abilities, will try to minimise any rate shock.

2-Staff-13

Ref: Chapter 2 Appendices, Tab 2-AA – Capital Projects

(a) Please update tab 2-AA to include 2017 actuals to date.
(b) Please explain any significant variances from the 2017 budget to actuals.

Response:

a) & b) Please see “Preamble” for an update table and notes on significant variances.

2-Staff-14

Ref: Exhibit 2/Section 2.2.1/Pages 19-26 – Gross Assets

In Tables 9-12, Cooperative Hydro Embrun has provided a list of 2018 capital projects. The total Test Year 2018 gross capital expenditures for all projects is $150,205 (excluding contributed capital).

(a) Are all of the listed projects and related capital expenditures totaling $150,205 expected to be placed in-service in 2018 and to be added to the 2018 Rate Base?

(b) If some of the projects that are listed are not expected to be in-service in 2018 and as a result will not be added to the 2018 Rate Base, please identify all such projects, the associated capital expenditure, and the expected in-service date.

Response:

(a) Apart from Versailles subdivision, CHEI confirms that all capital projects listed under 2018 are scheduled to be completed before year end 2018. A table showing the status of the Capital Projects is presented in the "Preamble" section of these responses.

(b) Not applicable.

2-Staff-15

Ref: Exhibit 2/Section 2.2.2/Page 28 – Accumulated Depreciation

The reference above is reproduced below:

CHEI has adopted depreciation rates based on the Kinectrics Asset Depreciation Study which can be found at this link [add link]. The rates used are presented below, and the Continuity Schedules of the Accumulated Depreciation are presented in the table below. CHEI's depreciation expense policy and methodology are provided on the next page. The depreciation expenses continuity schedules are presented at [references].

Please provide the missing link and references mentioned in the paragraph above.

Response:

https://www.oeb.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf

2-Staff-16

Ref: Exhibit 2/Section 2.3.3/Page 31 – Calculation of Cost of Power

Please update the Cost of Power forecast to reflect the most recent RPP prices from the OEB's Report issued on June 22, 2017 (effective July 1, 2017) for the period from January 1, 2018, to April 1, 2018.

Response:

The suite of models filed in conjunction with these responses uses the most recent RPP prices from the OEB's Report issued on June 22, 2017.

2-Staff-17

Distribution System Plan

Ref: Table ES-1: Historical Capital Investments by Year
Ref: Table ES-2: Forecast Capital Investments by Year

The forecasted system access budget is significantly less than the historical actuals, but Cooperative Hydro Embrun has stated it anticipates load to grow by over 30% between 2017 and 2023. Please provide an explanation on how Cooperative Hydro Embrun can meet increased load growth with a lower budget.

Response:

The Stantec report states that most of the growth will occur in 2019. (see snapshot below)

- South-East of Ste Marie and Castor 2016, 306 units under development, F03
- South-West of Ste Marie and Notre-Dame 2016, 61 units under development, F03
- North-East of Notre-Dame and Rue Manoir 2017, 41 units, F02
- North of Rue Blais at Notre-Dame 2019, 40 units, F03
- South-East of St Jacques and the Castor 2019, 50 units, F02
- South-East of Ste Marie and Notre-Dame 2019, 150 units, F03
- South-West of Ste Marie and the Castor 2019, 370 units, F04

The projected System Access expenditure shown at page 19 of the DSP also reflect the increase in load. With its operational resources allocated to connecting new growth, the utility anticipates that less System Renewal will occur in 2019 to offset the increase in System Access.

	2018	2019	2020	2021	2022
CATEGORY	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$
System Access	34,500	135,000	53,000	53,000	78,000
System Renewal	115,780	20,000	60,000	62,000	40,000
System Service	0	0	0	0	0
General Plant	5,700	5,700	5,700	5,700	5,700
Total	155,980	160,700	118,700	120,700	123,700

CHEI notes that in accordance with Board Policy, in order for a utility to include capital costs in its Test Year, the utility must attest that assets will be in service by the end of the Test Year – in this case, December 31, 2018. Therefore, budgets past 2018 do not reflect load growth past year end 2018.

2-Staff-18

Distribution System Plan

Ref: Overview of Assets Managed

Cooperative Hydro Embrun has stated that their system consists of about 15km of overhead lines and 12km of underground lines. Cooperative Hydro Embrun also plans to test wood poles to identify poles that are at end-of-life and in need of replacement. There has also been concern of a backup supply in the event of a failure at one of Cooperative Hydro Embrun's distribution stations.

(a) Can Cooperative Hydro Embrun provide a high level age demographic for the overhead and underground conductors? If it has not been historically tracked, does the utility intend to track this in an asset registry moving forward? If not, how does Cooperative Hydro Embrun budget replacement of these conductors when required?

(b) Does Cooperative Hydro Embrun intend to test all the poles in their distribution system to build an asset condition assessment of their pole population? If Cooperative Hydro Embrun only intends to test poles that are likely to fail, how does it currently identify this subset of poles?

(c) Has Cooperative Hydro Embrun done any condition assessments on their stations? Are there any inspection reports for each station that could be provided?

Response:

a) CHE only started tracking the age of its overhead and underground conductors as of 2002, therefore, it cannot the requested information. The only major change in overhead conductors is the installation of the 4th feeder. Cost estimates are provided by Sproule who also performs capital work for neighbouring utilities such as Hydro Hawkesbury and Ottawa Hydro.

b) This information was explained in detail at Section [5.3.1] Asset Management Process Overview of the DSP page 10 of 25. CHE intends to test them every four years.

c) As per APPENDIX C-Minimum Inspection Requirements, CHEI's (only) substation is inspected every six months. The last inspection report was done in May of 2017. The report is presented at the next page.

Substation Inspection
Every 6 Months
Cooperative Hydro Embrun

Station: Embrun St Jacques Station   Date: May 19, 2017   Time: 10:30am

Transformer Checks

		T1	
Temp Gauges (record and reset)	Tank	Act 33°C	Max 59°C
	Core	Act	Max
Check Terminations	√		
Check for Oil Leakage	√		
Check Oil Levels on Gauge	√		

Structure Checks

Visual and Audible inspection of Terminations		Visual Inspection of Switches	OK
Visual Inspection of Disconnects		Visual Inspection of Insulators	OK

Internal Checks

Visual Inspection of all battery terminals		Test battery cell voltage	#	V
Voltage on DC Supply	V	Low	#	V
		High	#	V

General Building/Grounds Checks

Check for signs of leaking roof, etc.	OK	Check for substation signage	OK
Check substation lighting	OK	Check for presence of rodents	OK
General building condition	OK	Check for signs of vandalism	OK
Check substation fencing and security	DEF	Condition of fire extinguishers	N/A

Station Readings

Feeder	Flags Timed	Flags Inst	Reset	R-Amps	W-Amps	B-Amps	Counter
1	Feeder #1	N/A	Yes	70/110	65/115	55/120	N/A
2	Feeder #2	N/A	Yes	110/205	70/115	100/140	N/A
3	Feeder #3	N/A	Yes	72/135	70/110	70/110	N/A
Total							
Stn Service Reading		kWhr	Stn Energy Reading		kW		kWhr

Deficiency and Follow Up

Description	Equipment Affected	Repair/Hazard	Priority Grd1	Priority Grd2
Security	Fence			√

Inspected By: John McCourt

d)

2-Staff-19

Distribution System Plan

Ref: Capital Actual Expenditure 2013

Cooperative Hydro Embrun spent $29,050 on pole replacement and $12,000 on transformer replacement in 2013. Please provide how many poles were installed and how many transformers were replaced.

Response:

CHEI replaced 6 poles and 3 transformers in 2013.

2-Staff-20

Distribution System Plan

Ref: Capital Actual Expenditure 2013
Ref: EB-2013-0122 Capital Budget 2013

Cooperative Hydro Embrun states that in its last cost of service application (EB-2013-0122) that there was a need to construct a 4th feeder in 2013 to address future load growth and had forecasted 800 customers will be connected to this feeder.

(a) Please provide the number of customers that have been connected to this feeder and the loading on this feeder.
(b) Please provide the length of the portion of feeder constructed in 2013.
(c) Please provide a business case or any planning documents for this four-year project.

Response:

a) Subdivision Faubourg Ste-Marie

Faubourg Ste-Marie Phase 1	Connected as to Date
365	130

WIP (not yet connected)

Faubourg Ste-Marie Phase 2	Connected as to Date
81	0

Faubourg Ste-Marie Phase 3	Connected as to Date
300	0

b) Length of feeders (km)

Substation to Ste.Thérèse	0.14 km
Ste-Thérèse Street	0.6 km

c) Please see Stantec System Load-Flow, and Optimization Study filed at Appendix C of CHEI's 2014 CoS EB-2013-0122.

2-Staff-21

Distribution System Plan

Ref: Capital Actual Expenditure 2014

Ref: EB-2013-0122 Capital Budget 2014

Cooperative Hydro Embrun had identified the system access project Faubourg Ste-Marie Subdivision in 2014. The two project accounts 1845 and 1850 had an estimated cost of $398,000 and $87,500, respectively, in the EB-2013-0122 Capital Budget. The actual expenditures reported in the Distribution System Plan for account 1845 and 1850 are $692,811 and $288,934 respectively.

(a) Please explain the variance of between the capital budget cost estimate in EB-2013-0122 and the reported actuals in this Distribution System Plan.

(b) Was there a capital contribution from the developer of the subdivision for this project? If so, how much?

(c) Please provide the business case for this project or any planning documents related to this project.

Response:

a) At the time CHE filed EB-2013-0122 no detailed description of the project other than preliminary plans and counts from the developer and municipality was known to CHE. The utility had been advised to expect and plan for 200 new connections by the end of 2014. Costs are shown in the table below.

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**
1850	TRANSFORMERS FOR THE PROPOSED SUBDIVISION AND LDC NEED	$ 87 500.00

In 2014 only one project went forward, Patenaude Subdivision (Faubourg Ste Ste-Marie) of EB-2013-0122). However, instead of the planned 100 units, the builder opted to build 365 units. (by end of 2014). Actual costs are shown below.

		Planned	Actual
1845	PARC RICHELIEU 4TH FEEDER PATENAUDE SUBDIVISION	$ 98 000.00	$ 149 175.00

	PATENAUDE SUBDIVSION (100 UNITS)	$ 120 000.00	$ 524 915.00
	ENGINEER COST PATENAUDE SUBDIVISION		$ 18 721.00
	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**	**$ 692 811**
1850	TRANSFORMERS FOR PATENAUDE SUDDIVISION	$ 87 500.00	**$ 288 934**

b) The capital contribution amount from the developer was $ 829,236.

c) Please refer to Appendix C of Exhibit 2 of CHEI's 2014 Cost of Service application for need and justification for this project (EB-2013-0122). *All the documents listed below are in a file at the CHE office.*

d) With regards to the planning documents, CHEI's process is described below, and all supporting documents are kept in hard copies at the utility's office.

- *Step 1 - Obtain approval from the Municipality on the development plan*
- *Step 2 - CHEI reviews and provides comments and conditions regarding the project.*
- *Step 3- The engineer prepares a draft project plan.*
- *Step 4- A meeting is held between the engineers of the developer and CHE (Stantec)*
- *Step 5- Once the comments were made by both parties' engineers, the final plan is completed.*
- *Step 6- An economic evaluation is calculated and provided to the developer*
- *Step 7- An Agreement is signed with the developer and CHEI*
- *Step 8- The release is signed by the developer that attests that the project is compliant with CHEI*

2-Staff-22

Distribution System Plan

Ref: Capital Expenditure Forecast to Year End 2017
Ref: Appendix C New Station Justification

Cooperative Hydro Embrun has planned a new substation transformer in the existing station for growing load demand and to provide redundancy to the system due to the loss of emergency backup supply from Hydro One. Cooperative Hydro Embrun also states that a transformer is working "harder" at ONAF and is not considered good engineering practice to continuously operate in this range.

(a) Please confirm how many subdivision units actually materialized in 2016 and 2017 compared to the estimates in Appendix C for South-East of Ste. Marie and Castor, South-West of Ste. Marie and Notre-Dame, and North-East of Notre-Dame and Rue Manoir.

(b) Does Cooperative Hydro Embrun have evidence that operating a transformer in its ONAF rating is bad engineering practice? Is the transformer not rated to operate continuously at the ONAF rating?

(c) What was the incremental cost of purchasing a 10MVA transformer compared to a 7MVA transformer?

(d) Does the existing transformer or the new transformer have overload capabilities? Please provide the transformer specifications and their summer and winter ratings.

(e) Please provide the cost breakdown of this project.

Response:

(a)

Subdivision	Year	Actual
South-East of Ste. Marie and Castor	2016	130
South-West of Ste. Marie and Notre-Dame	2017	Project delayed to 2018
North-East of Notre-Dame and Rue Manoir.(Versailles Project)	2017	Project delayed to 2018

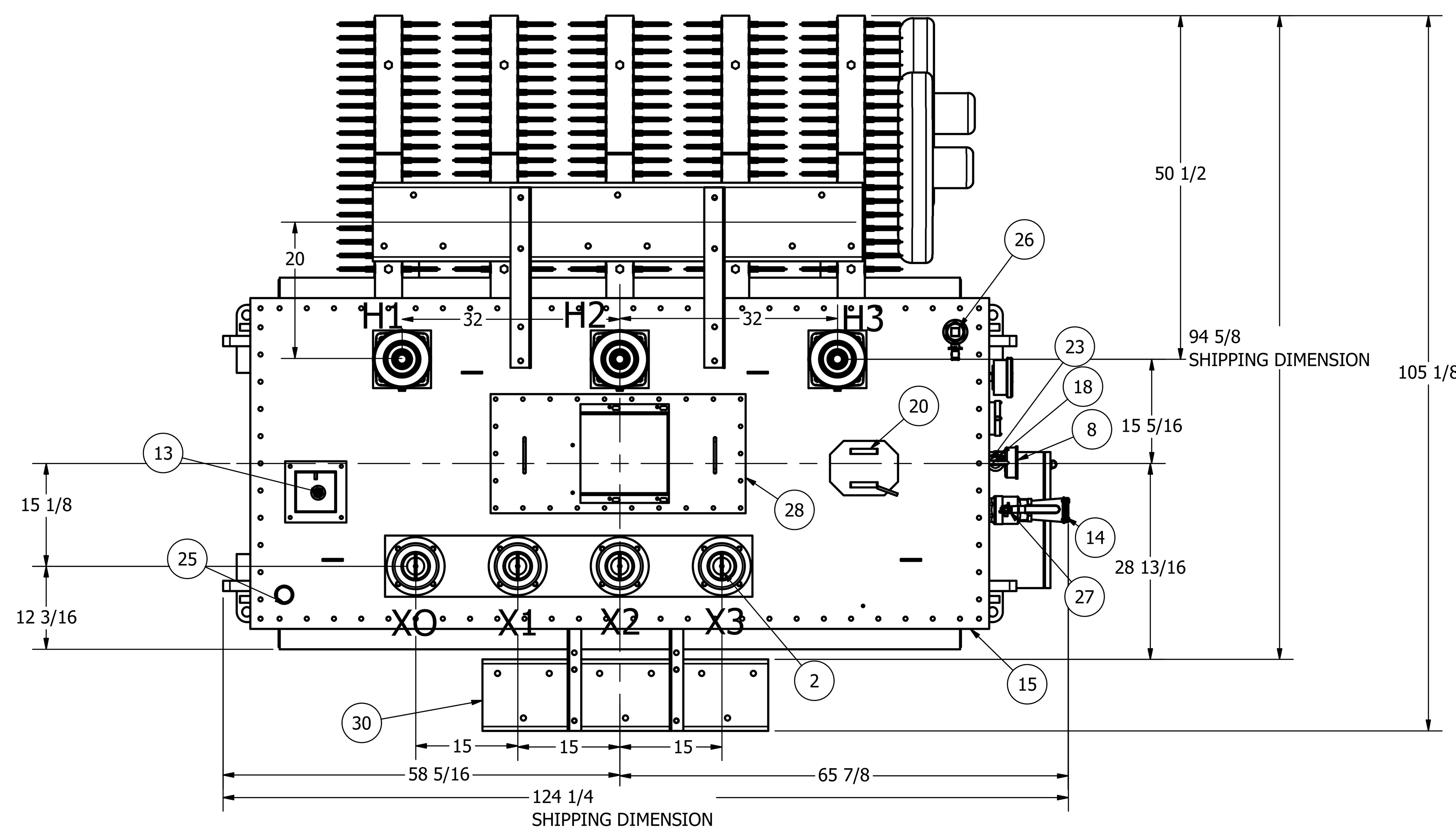
b) A transformer is designed to operate up to its ONAN rating without fans and to its ONAF rating with fans continuously. We do not believe that this operation (to the limits of its rating) is bad engineering practice, but were stating that the risks of a transformer failure increases as it is loaded to its limits, as it ages, etc. Stantec believes the submission to the OEB paraphrased this text from its report in a way that changed it slightly.

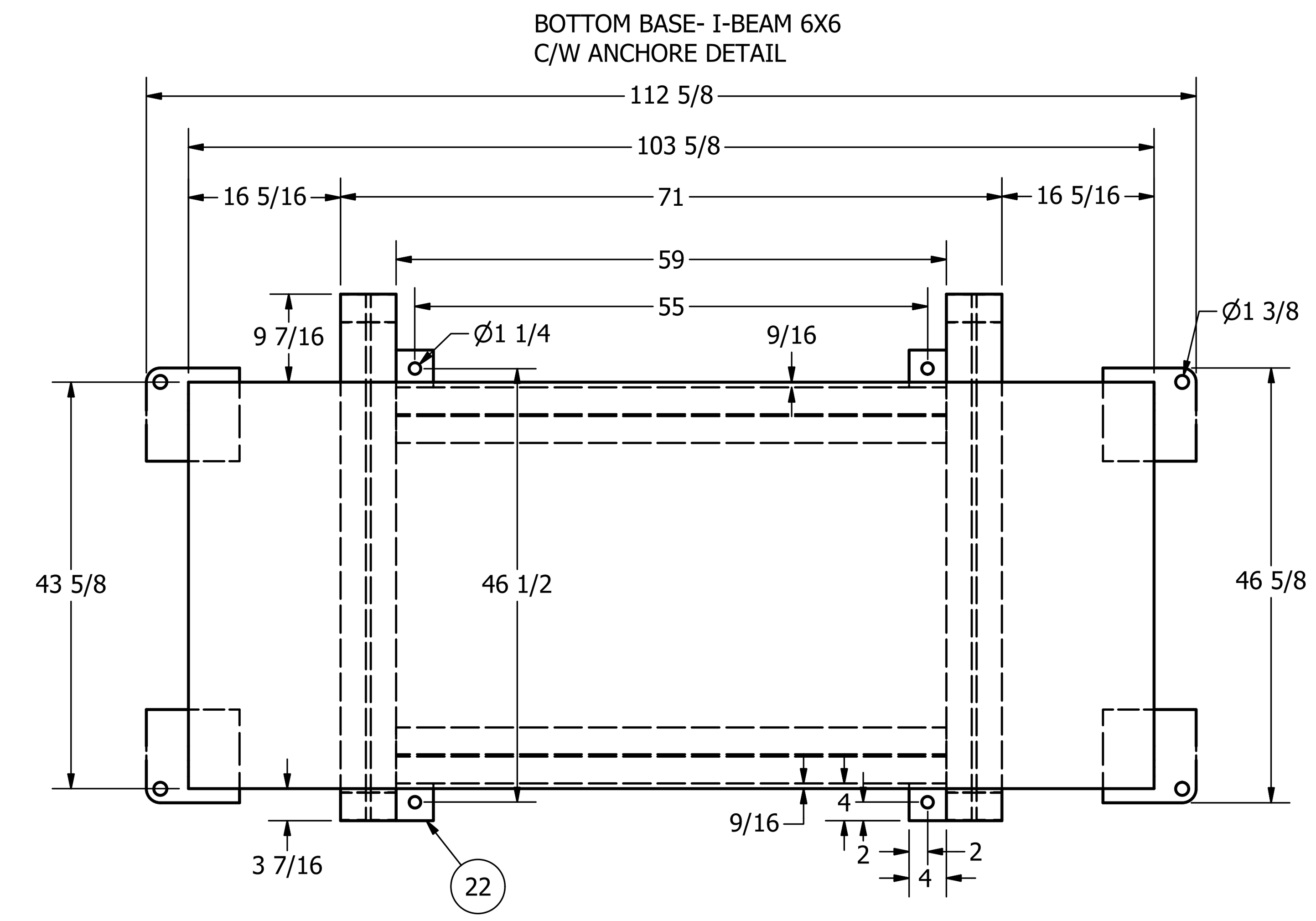
c) The cost for a 10MVA is approximately 25% to 30% more than a 7MVA.

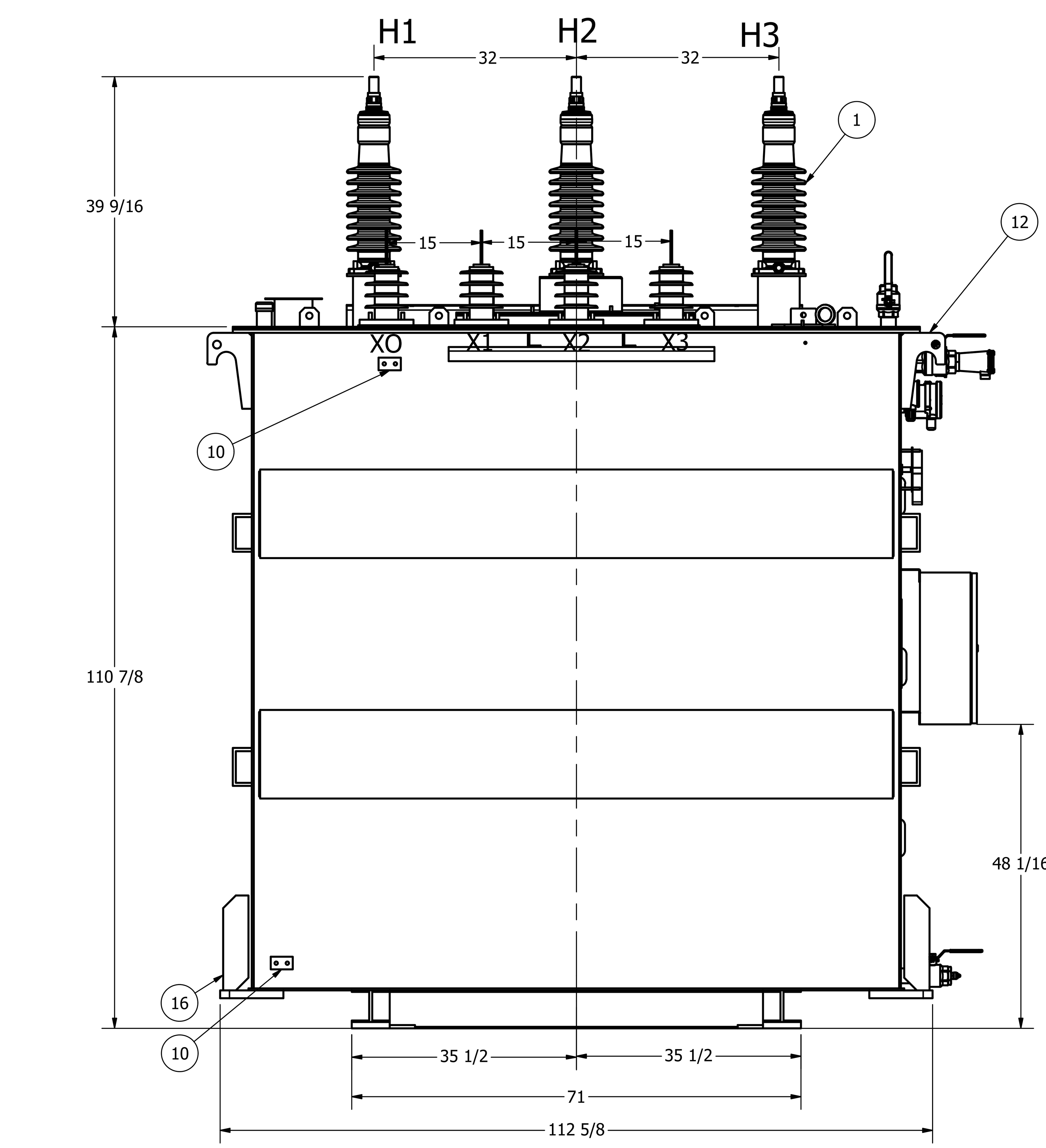
d) The new transformer does have a 10MVA ONAN, and 13.3kVA ONAF capability. Enclosed are the shop drawings. See engineering drawing at the next page.

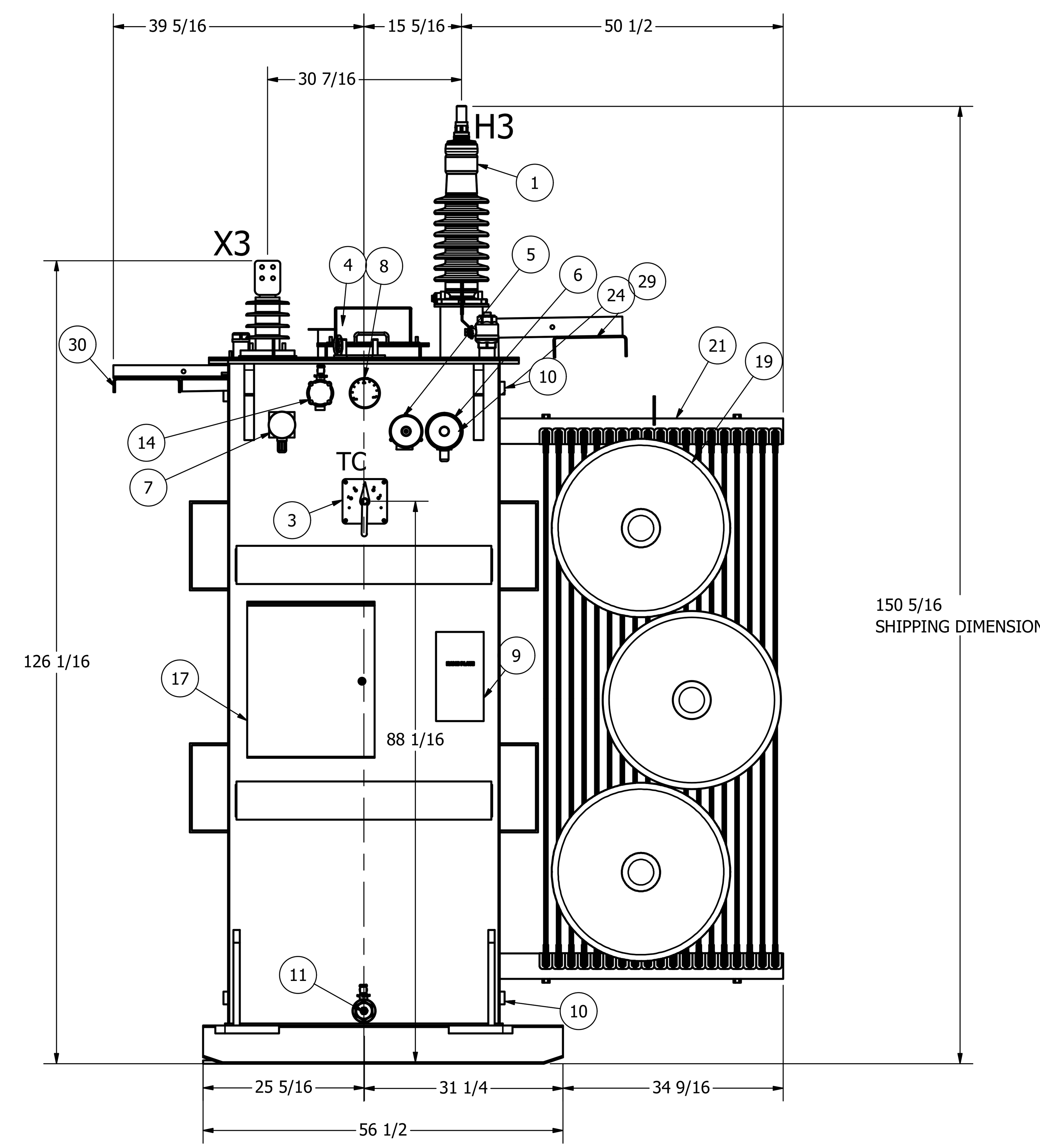
(e)

Description	Cost
Engineer Cost	$30,000.00
Engineering 50/45/5	$125,000.00
General Conditions	$132,500.00
Civil Construction	$310,000.00
Equipment	$284,856.50
Material	$126,000.00
HV/MV Installation	$165,000.00
LV Installation	$18,898.00
Protection and Control	$39,341.50
SCADA/RTU Meters, Testing	
Communication and Integration	$41,800.00
Transformer	$244,000.00









PARTS LIST		
ITEM	QTY	DESCRIPTION
1	3	HV BUSHING 46 KV 250 KV BIL 400 A. ABB #T046W0412AU c/w 1 1/2" - 12 TH'D STUD 2 1/4' LG. (DRAW LEAD)
2	4	LV BUSH 15KV 110KV BIL 1227A 4-HOLE SPADE W#39A5103-1 VERT.MT
3	1	TAP SWITCH 250KV BIL 400A QUALITROL#1L0402505BS3-WLT-01 C/W PROVISION FOR PADLOCKABLE
4	1	PRESSURE RELIEF DEVICE QUALITROL 208-60U TYPE C/W SHROUD
5	1	OIL TEMP GAUGE MAX INDI TYPE C/W 2-CONTACTS QUALITROL# 167-224-01
6	1	WTI TEMP GAUGE MAX INDI TYPE C/W 3-CONTACTS QUALITROL#167-234-01
7	1	LIQUID LEVEL GAUGE c/w 1 CONTACTS QUALITROL#035-039-01
8	1	PRESSURE VACUUM GAUGE 10PSI QUALITROL# 050-35E
9	1	NAMEPLATE SS
10	4	SS GROUND PADS c/w 1/2"UNC TAPPED HOLES @ 1-3/4" CTRS
11	1	2" SS DRAIN BALL VALVE C/W 3/8" SAMPLING DEVICE
12	4	LIFT LUGS MEDIUM
13	1	CORE GROUND BUSHING C/W BOX
14	1	RAPID PRESSURE RISE RELAY c/w SEAL-IN RELAY QUALITROL #910-011-36/909-300-01 C/W SHUT-OFF VALVE
15	1	BOLTED TANK COVER
16	4	STEP JACKS
17	1	CONTROL BOX NEMA 4X SS (24" x 20" x 8") c/w 2 BREATHERS HEATER/THERMOSTAT
18	1	BLEEDER VALVE QUALITROL#351-2A
19	3	FAN 24D 850RPM 3900CFM 115V 1PH 1/6HP KZ#F24-A8606
20	2	FALL ARREST
21	5	WELDED COOLING RADIATORS 15"W 84" C TO C 19 SECTIONS
22	4	ANCHORE PLATE
23	1	1/4" PRESSURE -VACUUM GAUGE SHUT OFF S.S. BALL VALVE
24	1	THERMAL PLATE - WTF-1030-1 CS-48768
25	1	2" PLUG C/W CAP
26	1	TOP 2" SS FILL BALL VALVE C/W 3/8" SAMPLING DEVICE
27	1	2.5" S.S. SHUT-OFF VALVE FOR RAPID PRESSURE RISE RELAY
28	1	HANDHOLE COVER WITH 14"X34" CUT OUT OPENING
29	1	GALVANIZED LA'S BRACKET FOR HV ARRESTERS
30	1	GALVANIZED LA'S BRACKET FOR LV ARRESTERS

OIL FILLED TRANSFORMER 3PH 60Hz 65°C ONAN/ONAF
KVA - 10000/13333
HV - 44000V
LV - 8320Y/4800

	Ib	kg
VOL OF OIL		
- 5820 L	11010	4994
CORE AND COIL	26957	12228
TANK & FITTINGS	12424	5635
TOTAL	50391	22857

FINISH - ASA #70 GREY
SPEC. - CSA- C88-M90
OIL TYPE- NYNAS NYTRO BEAR
(STD MINERAL OIL)

NOTES:-
1. TANK DIMENSIONS
102"W X 42"D X 104"H
2. SHIP ITEM#30 LA BRACKET
SEPARATE WITH THE UNIT

REV.	REMARKS:	BY:	DATE:
3	CONTROL BOX NEMA 4X WAS NEMA4	PB	14/03/2017
2	ADDED LA'S BRACKETS FOR HV/LV	PB	6/3/2017
1	LV BUSH MOVED TO COVER WAS ON SIDE	PB	16/02/2017

NORTHERN TRANSFORMER

SCALE: 1=16	DRAWN BY: PBhatia	DATE: 31/01/2017	REV: 2
UNITS: IN	CHECKED BY: WEI	DATE: 01/02/2017	S. O. NO.: 17-2848

TITLE: OUTLINE
10/13.3 MVA OIL FILLED TRANSFORMER ONAN/ONAF
44000-8320Y/4800 V

PROJECT: EMBRUN HYDRO
DRAWING NO.: 2848-010D

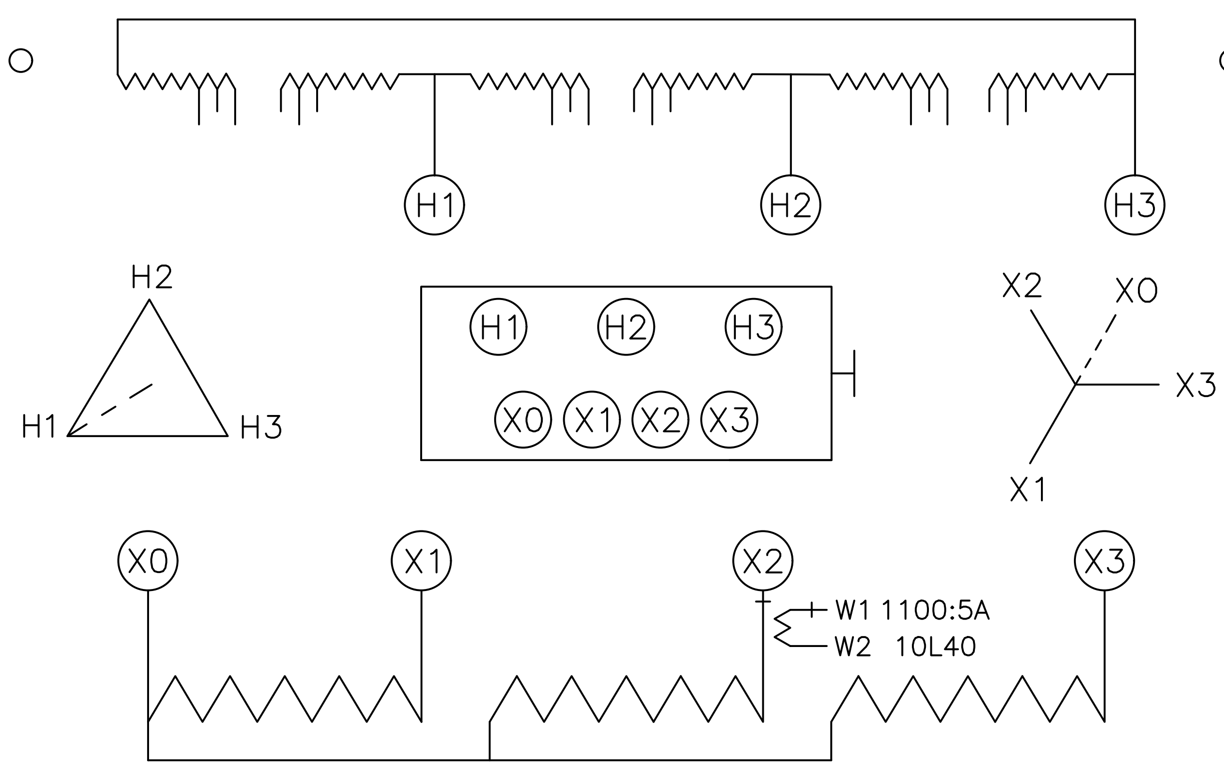
NORTHERN TRANSFORMER

ONAN/ONAF SEALED TRANSFORMER

SERIAL No.	17–2848	PHASE	3	Hz	60	DATE OF MFR.	2017
KVA	10000/13333	HV	44000	LV	8320/4800		

IMPEDANCE PERCENT AT 85 °C		
CORE & WINDINGS	12228	KGS
TANK & FITTINGS	5635	KGS
MINERAL OIL 5820 LITRES	4994	KGS
TOTAL MASS	22857	KGS
ONAN RATING AT AMBIENT OF 0°C	12500	KVA

VOLTS	TAP POSN	AMP @ 10 MVA	AMP @ 13.3 MVA	BETWEEN	VOLTS	AMP @ 10 MVA	AMP @ 13.3 MVA	BETWEEN
46200	1	125.0	166.6					
45100	2	128.0	170.7					
44000	3	131.2	175.0	H1 H2 H3	8320	694	925	X1 X2 X3
42900	4	134.6	179.4					
41800	5	138.1	184.2					



CAUTION: DO NOT OPERATE TAP SWITCH WITH TRANSFORMER ENERGIZED

SPECIFICATION CSA C88–M90 & C802.3–15		
INSULATION LEVEL	HV 250 KV	LV 110 KV
MAXIMUM TEMPERATURE RISE 65°C		
WINDING MATERIAL COPPER		
TANK PRESSURE +8 PSI /–14.7 PSI /+55 kPa /–101kPa		
PURCHASER'S P.O. No.: #TBD		

DESIGN IMPEDANCE: 6.4 %
ACTUAL IMPEDANCE WILL
BE ON NAMEPLATE AFTER TESTING

MATERIAL – .032 STAINLESS STEEL
7" X 13"

REV.	REMARKS	DRAWN BY	APPRO. BY	DATE:
3	CHANGED IMPEDANCE 6.4% WAS 6.45% ONDWG	PB		MAR 14/17
2	CHANGED VECTOR FROM DYN1 TO DYN11	RB		MAR 06/17
1	CHANGED LV BUSHING LOCATION	RB		FEB 16/17

NORTHERN TRANSFORMER

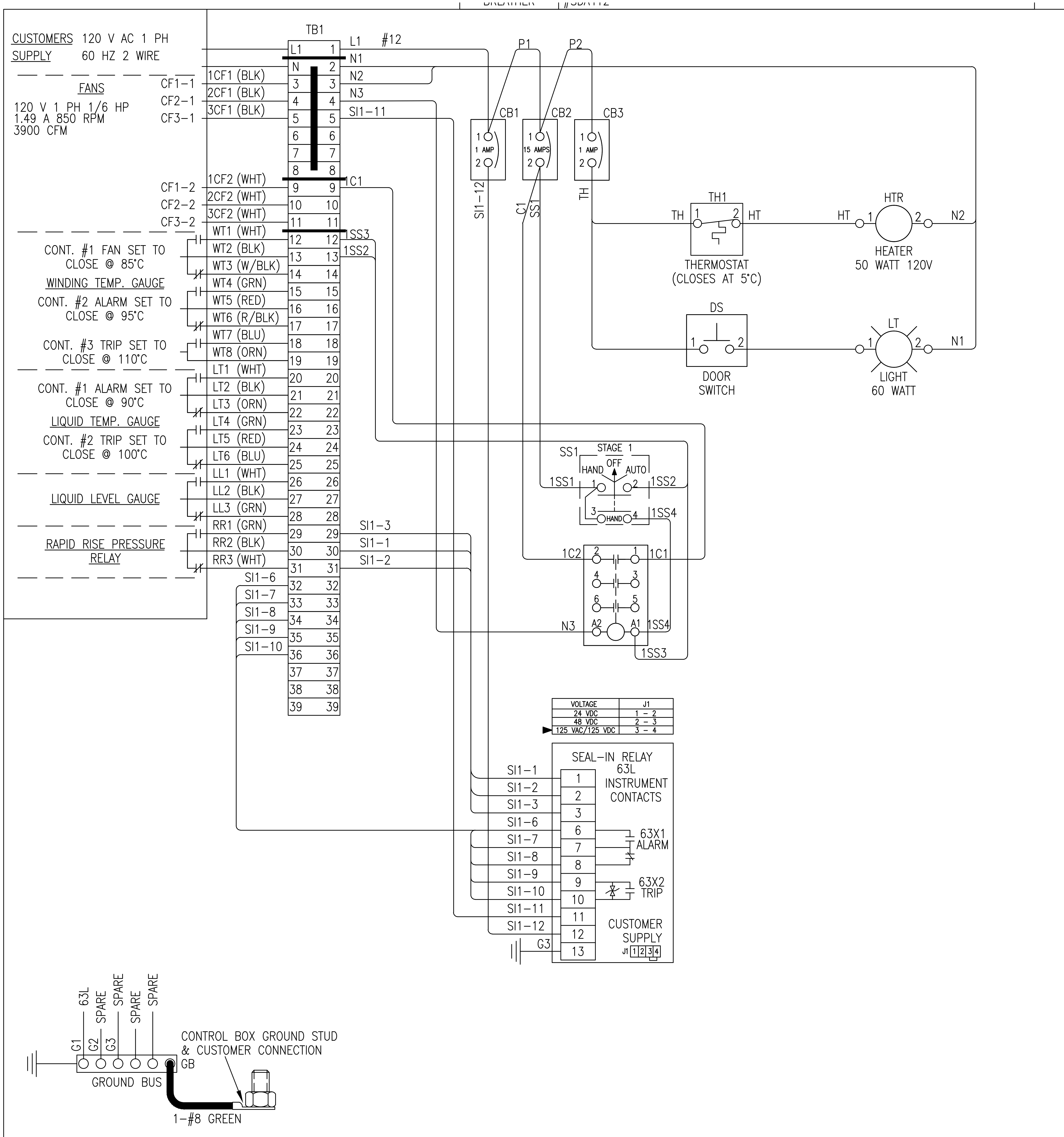
PLOT 1=1	DRAWN BY: ROHIT BATTA	DATE: JAN 17/17	REV. 3
JOB:	APPROVED BY:	DATE:	S.O. NO. 17–2848

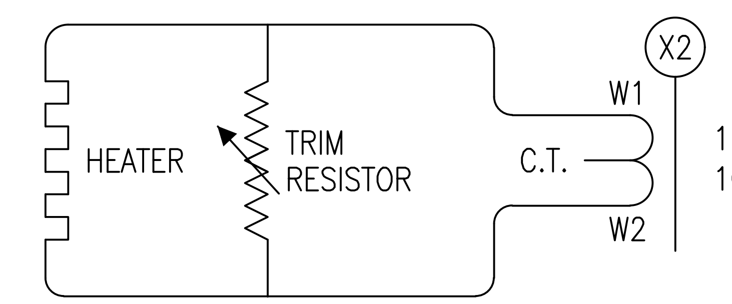
TITLE: NAMEPLATE
10000/13333 KVA LIQUID FILLED TRANSFORMER ONAN/ONAF
44000–8320Y/4800 V 3 PH 60 HZ 65°C

KLINE
PROJECT: EMBRUN HYDRO SUBSTATION

DRAWING NO. 2848–020C

CONTROL BOX





WINDING TEMPERATURE INDICATOR
SIMULATED SYSTEM

TAG No.	ITEM	DESCRIPTION
CB1,CB3	CIRCUIT BREAKER 1P 1 A	SCHNEIDER #60118
CB2	CIRCUIT BREAKER 1P 15 A	SCHNEIDER #60129
HTR1	HEATER 50 W 120 V	ETIREX #SCB-50 253809H
SS1	SELECTOR SWITCH	IDEC #ASD320N
C1	CONTACTOR 120 V 20 A 3P	SQUARE D #8910DPA13V02
TH1	THERMOSTAT 15 A NC	STEGO #01146.9-00
63L	SEAL-IN RELAY	QUALITROL #909-300-01
TB1	TERMINAL BLOCK	WEIDMULLER SAK 10 EN #0337660000
GB	600 VOLTS 8-14 AWG	ILSCO #N174AS

INSTRUMENTS WIRES #16 SOOW
POWER WIRES #12 TEW BLACK
CONTROL BOX WIRES #14 TEW BLACK
GROUND WIRES #8, #14 TEW GREEN
NEUTRAL WIRES #14 TEW WHITE
1 BREATHER

REV.	REMARKS	DRAWN BY	APPRO. BY	DATE:

NORTHERN TRANSFORMER

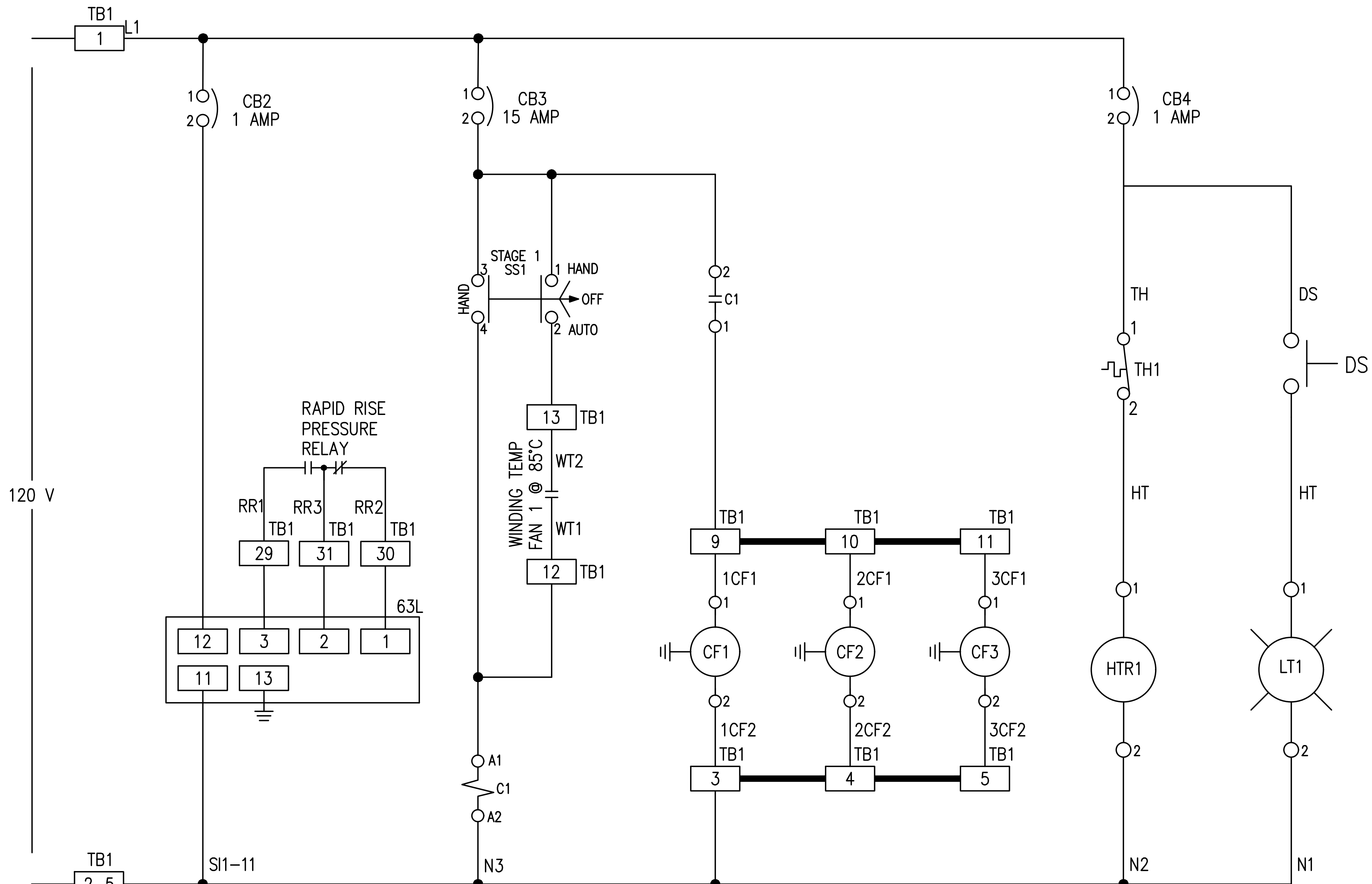
PLOT 1=1	DRAWN BY: ROHIT BATTA	DATE: JAN 31/17	REV. 0
JOB:	APPROVED BY:	DATE:	S.O. NO. 17-2848

TITLE: WIRING DIAGRAM
10000/13333 KVA LIQUID FILLED TRANSFORMER ONAN/ONAF
44000-8320Y/4800 V 3 PH 60 HZ 65°C

KLINE
PROJECT: EMBRUN HYDRO SUBSTATION

DRAWING NO. 2848-030C

SCHEMATIC



STANTEC PROJECT #: 163302179

SUBMITTAL # Transformer

This review by Stantec is for general conformance with the design concept of Stantec's design of the:

- [ ] Architectural
- [ ] Structural
- [ ] Mechanical
- [x] Electrical
- [ ] Other

component(s) only and does not mean that Stantec has verified or approves the shop drawing(s). The Contractor remains solely responsible for the shop drawing(s) and this review by Stantec does not relieve the Contractor of the Contractor's responsibility for errors or omissions in the shop drawing(s) or for meeting all requirements of the contract documents. This review does not mean that Stantec approves the detailed design inherent in the shop drawing, responsibility for which shall remain with the Contractor submitting same, nor does this review mean that Stantec accepts any deviation of the shop drawing(s) from the contract documents. The Contractor is responsible for confirming all dimensions and correlating them at the job site, for all construction means, methods and techniques, and for coordination of construction work of all trades, including coordination of all shop drawings.

Stantec

- [x] REVIEWED
- [ ] REVIEWED, AS NOTED
- [ ] REVISE AND RESUBMIT
- [ ] NOT REVIEWED

DATE 2017-03-30

BY Krista Bochert

REV.	REMARKS	DRAWN BY	APPRO. BY	DATE:

NORTHERN TRANSFORMER

PLOT: 1=1 | DRAWN BY: ROHIT BATTA | DATE: JAN 31/17 | REV. 0

JOB: | APPROVED BY: | DATE: | S.O. NO. 17–2848

TITLE: SCHEMATIC
10000/13333 KVA LIQUID FILLED TRANSFORMER ONAN/ONAF
44000–8320Y/4800 V 3 PH 60 HZ 65°C

KLINE
PROJECT: EMBRUN HYDRO SUBSTATION

DRAWING NO. 2848–032B

2-Staff-23

Distribution System Plan

Ref: Capital Forecast Expenditure 2020-2021

Cooperative Hydro Embrun has identified that there is a need over two years to replace transformer cut-outs and arrestors due to safety concerns. In 2020, Cooperative Hydro Embrun has budgeted $40,000 for these projects. Please provide how many cut-outs and arrestors were replaced for each year over the two- year period.

Response:

CHEI has yet to replace transformer cut-outs and arrestors. However, the utility anticipates that there is a strong possibility that replacement will be required, given the age of the underground distribution system. CHEI therefore, turned to Sproule Power Line (SPL) to obtain an estimate for future years. $40,000 was a based on historical costs and best estimate based on SPL's knowledge and expertise.

2-Staff-24

Distribution System Plan

Ref: Capital Forecast Expenditure 2018-2022 – General Plant

Cooperative Hydro Embrun has budgeted $5,700 for the general plant category for software, office equipment, and computer & hardware. Although this amount does not meet the materiality threshold, it is a repeated yearly cost. Please provide some information on how Cooperative Hydro Embrun plans to spend this money and why there is a yearly upkeep.

Response:

These budgets are CHEI's best estimate based on historical costs and as Staff acknowledged, $5,700 is well below the materiality threshold.

Computer and Hardware

The projections represent computer upgrades, printer, scanner, hard drives, and monitors. CHEI is of the view that providing its employees with up to date tools saves time and makes them more productive.

Software

Software upgrades and updates on its billing and other systems are for the most part out of the utility's control but notes that upgrades and updates are often required to address OEB changes to rules and policies.

Office Equipment

Over a five-year period, CHEI anticipates that some expenditure in this category will be required.

Given the escalating costs of computer hardware and software, CHEI find the projected increase to be modest.

2.0-VECC-3

Reference: Exhibit 2/pgs. 13-15

a) Please provide the capital contributions associated with each of the following projects (capital expenditures listed in bracket):
   - Faubourg Ste-Marie ($1,001,927);
   - Oligo Project Quatre Saison ($239,868)
   - Versailles III Subdivision ($119,200)

Response:

(a) Capital contributions are as follows:

- Faubourg Ste-Marie $829,239
- Oligo Project Quatre Saison $112,313
- Versailles III Subdivision not going forward in 2018

2.0-VECC-4

Reference: Exhibit 2/pg.15 & DSP pg.14

a) Please provide the current status (expected in-service date and cost) of the new substation.
b) What will be remaining undepreciated value of the existing municipal station (original 1988) at year-end 2017?

Response:

(a) The expected in-service date is November 15, 2017. Cost and work schedules are provided at the next page. Pictures of the substation being delivered were posted on social media.

(b) The gross value of the existing substation at the end of 2017 is $410,310. The depreciated value at the end of 2017 is $104,520 (as per the fixed asset continuity schedules).

Hydro Embrun
Pay App - Progress Billing
30-Sep-17

Description	Total Value	Overall Percent Complete	Percent Completed This Billing Period	* Billed to Date	Remaining to Bill	30-Sep-17
Contract Value	**$ 1,487,396.00**					
Engineering	$ 125,000.00	95.00%	0.00%	$ 118,750.00	$ 6,250.00	
General Conditions (PM, Trailer, Signage/Site Set-up, Bonding, Construction Supervison etc.)	$ 132,500.00	88.68%	18.87%	$ 117,500.00	$ 15,000.00	$ 25,000.00
Civil Construction	$ 310,000.00	90.32%	32.26%	$ 280,000.00	$ 30,000.00	$ 100,000.00
Equipment	$ 284,856.50	100.00%	52.66%	$ 284,856.50	$ -	$ 150,000.00
Material	$ 126,000.00	68.25%	47.62%	$ 86,000.00	$ 40,000.00	$ 60,000.00
HV/MV Installation	$ 165,000.00	18.18%	15.15%	$ 30,000.00	$ 135,000.00	$ 25,000.00
LV Installation	$ 18,898.00	0.00%	0.00%	$ -	$ 18,898.00	
Protection and Control	$ 39,341.50	34.51%	34.51%	$ 13,575.00	$ 25,766.50	$ 13,575.00
Scada RTU,Meters Communication and Integration	$ 41,800.00	0.00%	0.00%	$ -	$ 41,800.00	
Transformer**	$ 244,000.00	100.00%	0.00%	$ 244,000.00	$ -	
Totals	**$ 1,487,396.00**	**78.98%**	**25.12%**	**$ 1,174,681.50**	**$ 312,714.50**	**$ 373,575.00**
Hold Back at 10%				**$ 117,468.15**		**$ 37,357.50**
Payment Due						**$ 336,217.50**

* Includes current period billing
**Transformer payment is based on 10% on order, 20% on release of drawings, 20% for core material, 50% when landed.

Hydro Embrun Payment Schedule
30-Sep-17

Approximate Cashflow Liability Only

Contract Price $ 1,487,396.00

Description	Cost	Feb-28	Mar-31	Apr-30	May-31	Jun-30	Jul-31	Aug-31	Sep-30	Oct-31	Nov-15	Dec-15 45 Day Release
Engineering 50/45/5	$ 125,000.00		$ 62,500.00		$ 56,250.00						$ 6,250.00	
General Conditions	$ 132,500.00	$ 22,500.00			$ 15,000.00	$ 5,000.00	$ 10,000.00	$ 40,000.00	$ 25,000.00	$ 10,000.00	$ 5,000.00	
Civil Construction	$ 310,000.00						$ 20,000.00	$ 160,000.00	$ 100,000.00	$ 30,000.00		
Equipment	$ 284,856.50							$ 134,856.50	$ 150,000.00			
Material	$ 126,000.00							$ 26,000.00	$ 60,000.00	$ 40,000.00		
HV/MV Installation	$ 165,000.00							$ 5,000.00	$ 25,000.00	$ 110,000.00	$ 25,000.00	
LV Installation	$ 18,898.00									$ 18,898.00		
Proction and Control	$ 39,341.50								$ 13,575.00	$ 12,000.00	$ 13,766.50	
SCADA/RTU Meters, Testing Communication and Integration	$ 41,800.00									$ 21,000.00	$ 20,800.00	
Transformer*	$ 244,000.00	$ 73,200.00		$ 48,800.00			$ 122,000.00					
Total Invoice	$ 1,487,396.00	$ 95,700.00	$ 62,500.00	$ 48,800.00	$ 71,250.00	$ 5,000.00	$ 152,000.00	$ 365,856.50	$ 373,575.00	$ 241,898.00	$ 70,816.50	
Holdback	$ 148,739.60	$ 9,570.00	$ 6,250.00	$ 4,880.00	$ 7,125.00	$ 500.00	$ 15,200.00	$ 36,585.65	$ 37,357.50	$ 24,189.80	$ 7,081.65	$ 148,739.60
Total Paid	$ 1,338,656.40	$ 86,130.00	$ 56,250.00	$ 43,920.00	$ 64,125.00	$ 4,500.00	$ 136,800.00	$ 329,270.85	$ 336,217.50	$ 217,708.20	$ 63,734.85	$ 148,739.60

*Transformer payment is based on 10% on order, 20% on release of drawings, 20% for core material, 50% when landed.

2.0-VECC-5

Reference: Exhibit 2/pg.22 & DSP/pg.2 & Appendix G Stantec Study section 5.1.1

a) At the above reference the following statement is made: "*A new feeder was also required to supply the new subdivisions and provide security of supply since Hydro One is no longer able to provide any backup power to CHEI*." Please explain what backup supply was withdrawn by Hydro One and why.
b) Specifically address the reasons why Hydro One is dismantling their Embrun Distribution Station.
c) Please provide the notification received from Hydro One regarding this station.
d) At section 5.1.1 of the Stantec Study the authors make this observation:

The current method of providing the required redundancy is by using a feeder from each of the Hydro-One substations located to the east and west of Embrun. Each of the two feeders could provide support for 3.6 MVA of loading on an 'as required' basis. Using this method as a temporary way to provide the required redundancy means that the purchase of a second transformer or construction of another substation could be deferred until required for capacity reasons. It is our belief that Embrun Hydro is still covered by this Hydro-One program and Hydro-One is contractually obligated to provide 2 years notice to Embrun Hydro before the removal of the emergency supplies. While formal notice has not been provided, Hydro One has indicated that they may be decommissioning the station to the east of Embrun in the near future.

Does Embrun agree with Stantec's conclusion that Hydro One is obligated to provide 2 years notice and which is has not yet formally done? Or is the letter dated October 17, 2016 at Appendix I the formal notification by Hydro One?

Response:

(a) Please refer to Appendix I – Letter from Hydro One That the Temporary Distribution Facility Allocation Agreement is being Terminated for Hydro One's reasons for terminating the agreement.
(b) Please refer to Appendix I – Letter from Hydro One That the Temporary Distribution Facility Allocation Agreement is being Terminated for Hydro One's reasons for terminating the agreement.
(c) Please refer to Appendix I – Letter from Hydro One That the Temporary Distribution Facility Allocation Agreement is being Terminated The letter at Appendix I of the DSP states "Hydro One is providing Hydro Embrun with 2 years prior written notice of termination in accordance with Section 6 of the Agreement."

2.0-VECC-6

Reference: Exhibit 2/DSP pgs. 8 &11

a) If available, please provide SAIDI and SAFI by cause code. If not available, please explain when Embrun will begin collecting data to provide losses by cause code.
b) Please explain the high SAIDI/SAIFI (both with and without loss of supply) in 2016.

Response:

a) Please see Section 3.1 Asset Management Process of the DSP. Specifically, page 11/25 states: *The historical customer reliability data is identified in Figures 3 and 4. As can be seen, the reliability performance of the system has been very good. As a result, other than reporting the data to the OEB, there has not been a great need to perform extensive analysis. As a result of this DSP, CHEI will be making changes to its recording of outage information and the analysis it performs so that individual outages can be analyzed by cause code and related to feeder in future.*

b) SAIDI and SAIFI results in 2016 are due to a scheduled interruption for a capital project related to elbow insert program (Transformer). DSP, Page 23/120.

2.0-VECC-7

Reference: Exhibit 2/DSP/pgs.10,15, 18

a) For the major asset categories (e.g. breakers, wood poles, distribution transformers, underground cables, underground switches, overhead conduit etc.) please describe the asset condition assessment methods used by Embrun.

Response:

(a) The assessment method is described in detail in Section 5.3 Asset Management Process of the Distribution System Plan. Select excerpts of the relevant sections are reproduced below for ease of reference, however, please refer to Section 5.3 of the DSP for details on CHEI's condition assessment methods.

POLES:

Ref; Section 3.2 DSP page 10

CHEI records comprehensive information about its poles and transformers. Information is entered into a spreadsheet, one sheet for poles and one sheet for transformers. The spreadsheets record the particulars of the asset such as class, height, location and pole number as well as condition information for poles and location number, location, manufacturer, voltage and KVA, date installed and condition information. Condition information is as of the last inspection which is performed every four years. The asset records are used for equipment inspections, and the condition is updated after the inspection is carried out. Deficiencies are noted, and repairs or replacement is carried out the following year unless the condition will have a high probability of causing an environmental incident or a power outage or be a danger to the public, in which case the work is done as soon as possible. Depending on the capital already required this work may also be deferred where possible. At a minimum, it is smoothed and spread in phases so that the impact is mitigated where possible. This is also done within the constraint of maintaining efficiency by creating reasonable quantities of work to be done. Because the system is small, often the cost of the work required is less than the materiality threshold.

Ref; DSP Section 3.2 page 17

CHEI has 432 wood poles of various heights and classes. It does not capture the date installed, at this time, so no age distribution can be provided. Pole age for existing poles would be difficult to impossible to determine since no date nails exist in the poles and many of the poles, particularly the older ones, have no readable date information on them. CHEI addresses this by having frequent inspections to ensure the integrity of the pole structures. In addition, they have purchased pole testing equipment together with Hawkesbury Hydro to be able to perform more scientific testing.

The current and future pole testing method results in the identification of poles that are at end of life and need to be replaced. These poles are included in the capital plan.

CHEI has taken the development that has taken place and is projected to take place in the area in the near future into account. The existing system was inadequate to provide the load into the future and the voltage at the customer's premises was forecast to inadequate. In response to this CHEI has increased the station transformer capacity in 2017 by installing a new substation with 33% more capacity by installing a 10 MVA unit (ONAN). Both the old station and the new station transformers have fans installed to provide an emergency rating (ONAF). This new station is expected to be adequate to supply the existing and forecast new load into the foreseeable future. An additional 4th feeder was also installed and is now in place, to provide for better voltage regulation and load transfer options particularly in outage situations while suppling new subdivision load.

Because of the lack of backup power from Hydro One and the non-availability of Mobile Unit Substations from Hydro One, CHEI has opted to retain the existing station as a backup should the new station develop a fault and be forced out of service. The old station would allow full load to be supplied on most days with load curtailment happening only on the peak load days when the load exceeds the emergency rating of the old transformer. In this way redundancy is provided, while the failed unit is repaired, at the most reasonable cost available to CHEI.

DISTRIBUTION STATION

Ref; DSP Section 3.3 page 17-18

CHEI also performs maintenance and inspection activities in part to meet the requirements of the Distribution System Code on a three year cycle consistent with the requirements of an urban system but also to ensure its equipment continues to operate in an economical manner and promotes a safe environment for the general public and its workers. Any deficiencies are noted and corrected in a timely manner.

The MS transformer is maintained on a cyclical basis and standard oil testing is done annually. Similarly station feeder switches and protection is maintained.

TRANSFORMERS

Ref; DSP Section 3.3 page 18

Transformers are checked visually for evidence of abnormal heating at the primary and secondary connections. Typically this is a connection problem that is corrected without removing the transformer. Transformers can have damaged bushings or oil leaks. These conditions would be cause to replace the transformer. Some transformers have evidence of corrosion. If this is just surface rust, the surface is cleaned, repainted, and left in service. Where the rust is severe and has weakened the tank wall the transformer is replaced.

SWITCHES

Ref; DSP Section 3.3 page 18

Switches are maintained by cleaning and lubrication on a cyclical basis. Where the switch is damaged it is replaced as required.

CHEI also uses the experience of its line contractor including considering the experience of other utilities. An example is the replacing the porcelain fused cutouts with polymer fused cutouts and replacing porcelain air gap type lightning arrestors with polymer, solid dielectric arrestors. These projects are being planned proactively because of the problems with this equipment in various utilities even if it has not caused outages or health risks at CHEI. CHEI believes that if they do nothing these devices will cause problems in future. By being proactive *the excellent reliability record as well as health and safety record can be maintained.*

CUT OUT SWITCHES & ARRESTORS

Ref; DSP Section 2.3 page 9

…The remaining work forecast is the replacement of end of life poles as identified by testing and the replacement of porcelain fuse cutouts and porcelain air gap arrestors at transformers that present potential safety hazards to the line crews and in the case of air gap arrestors to the public as well. These works will be phased to smooth rate impacts. The switch and lightning arrestor program is an example of CHEI using information based on identified problems in other utilities, it recognizes that the same problems may occur on its system and proactively plans to address them within the constraints of rate impacts. These discretionary investments are modest and are planned to be undertaken to maintain the excellent reliability and safety record of the utility.

OVERALL APPROACH

Ref; DSP Section - CATEGORY-SPECIFIC REQUIREMENTS FOR THE PROJECT

CHEI has taken the approach that the items most at risk need to be replaced first. This means the poles that failed inspection and transformers with oil leaks and cracked insulators. Next is the completion of Load break elbow and insert replacement program. These devices are used whenever switching takes place on the underground system. CHEI then addresses devices on its system that although it has not experienced problem yet it is well known in the industry that the devices have known problems and defects that affect reliability and crew safety. These programs are carried out on a modest pace demonstrating due diligence and financial stewardship.

2.0-VECC-8

Reference: Exhibit 2/DSP/pg. 140 PDF

Pre-amble: At the above reference Embrun makes the following statement:

CHEI considered the possibility of operating with the current equipment and then, in the event of a failure, responding by making an emergency purchase of a transformer and work required to install it and put it into service. This would put all the customers out of service for as long as it takes to purchase, transport, install and commission the equipment. There is no assurance that the appropriate capacity and voltage ratios transformer will be available, nor assurance of the age, condition and delivery time of the unit. Further, costs for the unit, transportation and the installation will likely be at a premium. This solution was not considered further. This was also the only alternative since Hydro One had already indicated that it could no longer provide a backup feeder supply nor could it provide a mobile unit substation.

a) Please explain if the option of purchasing an emergency transformer and keeping it on site was considered for backup service.

Response:

(a) All options, including the suggestion above, was considered. However, with the slow yet steady anticipated growth in the service area going forward, combined with Stantec's consistent findings with respect to system load, the utility felt that a backup emergency transformer was a temporary "Band-Aid" solution and was deemed to be an imprudent option.

2.0-VECC-9

Reference: Exhibit 2/DSP/Appendix G Stantec Study, section 3.3 (PDF pg.170)

a) At section 3.3 of its Report Stantec recommends system upgrades to reduce losses. Has Embrun undertaken this recommendation, if not does it intent to and when?

Response:

(a) In 2017, CHEI's focus has been to make sure that the Substation is installed on time and budget. As it has in the past, CHEI takes Stantec's recommendations seriously and plans on performing the suggested upgrades starting in 2018. CHEI notes that all costs associated with the recommendations are part of the utility's Operation and Maintenance programs.

2.0-VECC-10

Reference: Exhibit 2/DSP/Appendix G Stantec Study/section 5.1.2

a) At the above reference the authors of the study state that: "[T]*he construction for the new substation has been awarded as a design-build project to K-Line Maintenance & Construction Ltd. for approximately $1.5M plus taxes*." Was the substation the project approved and tendered before the Stantec Study was complete? Please clarify the timing of the Stantec Study and the awarding of the contract to build the substation.

Response:

(a) A table showing the timelines of the various studies and events are shown below.

The recommendations from Stantec 2011 Load Flow study, which was filed in CHEI's 2014 Cost of Service application, indicated that a new substation was needed and, therefore, CHEI starting planning for the construction of the substation back in 2014. CHEI notes that although the report was issued on December 20th, 2017 the evaluation was done around the same time as the 44kV Substation Capacity and Redundancy Upgrade Design-Build Performance Specs. CHEI finds Stantec's Load Flow study to be a very useful asset evaluation tool and would have commissioned it regardless of the substation build.

Date	Service	Engineering Firm
May 10, 2011	Load Flow and Optimization Study	Stantec
	Hydro One letter	
October 19, 2016	44kV Substation Capacity and Redundancy Upgrade & Design-Build Performance Specs issued for Tender	Stantec
Dec 20, 2016	Utility Load Flow and Evaluation Study	Stantec
Dec 2016	Awarded to K-Line	K-Line

2.0-VECC-11

Reference: Exhibit 2/DSP/Appendix G Stantec Study/section 5.2 & 5.3

a) Please indicate which of the recommendations set out in the Stantec Study are being addressed by Embrun in 2017 and 2018 and which recommendations are being addressed post 2018.

Response:

(a) As explained at CHEI's response to 2-VECC-9, in 2017, CHEI's focus has been to make sure that the Substation is installed on time and budget. As it has in the past, CHEI takes Stantec's recommendations seriously and plans on performing the suggested upgrades starting in 2018. CHEI notes that all costs associated with the recommendations are part of the utility's Operation and Maintenance programs. A detailed status update is shown below

Stantec recommendations	**Status**
• Install reclosers with the construction of the new substation.	Done
• New modern digital metering for feeders F1, F2, and F3 within the substation are being installed under the substation upgrade project expected to be finished October 2017. This metering will provide all basic electrical parameters (voltage, current, PF, power, energy, and demand), plus power quality parameters (sags and swells, harmonics, transients, flicker), data and waveform logs (triggering, min/max, trending, timestamps), communications, set points, and alarming. This upgrade will allow trending to be done to confirm the pattern of daily loading, and to trend future load growth.	Done
• Update system single line to add further system information, including the source of transformers #477-75 and #476-75 on Centenaire Street, conductor sizes for all major feeders, and ampacities of all switches. (Budget $15,000)	Operation and Maintenance programs 2018-2019

• The system main feeders should be measured before rebalancing to verify the imbalance, and then the re-phasing should be done. (Budget $5,000)	Operation and Maintenance programs 2018-2019
• Confirm Switch S#846 rated ampacity. If the ampacity is found to be less than 150A the switch will need to be replaced with a switch rated for a minimum 150A to accommodate future emergency condition.	Operation and Maintenance programs 2018-2019
• Either rebalance feeders as new loads added in 2016-2022 or rebalance current loading within feeders 1, 2, 3 and 4 to minimize losses, possible options to rebalance include the following:	Operation and Maintenance programs 2018-2019

Exhibit 3 – Operating Revenue

3-Staff-25

Ref: Load Forecasting Model, Tab “Bridge&Test Year Class Forecast”

It appears as though there is a formula error in cell B42. OEB staff notes that the cell currently sums I129-I140 from the “Input –Customer Data” tab. OEB staff believes the cell should sum I140-I151. Please make the necessary corrections to the re-filed Load Forecasting Model.

Response:

The model filed with these responses has been updated to reflect the suggested correction above.

3-Staff-26

Ref: Load Forecasting Model, Tab "Bridge&Test Year Class Forecast"

OEB staff observes that the demand data (kW) shows a decrease of approximately 45% from 2016 to 2015 (from 1050 to 576 kW) for the Street Lighting rate class. However, the kWh consumption levels have not decreased by a proportionate percentage.

(a) Please provide an explanation.

(b) Please recalculate the kWh for 2016 using an average kW/kWh ratio from 2007 to 2015.

Response:

(a) This was a simple case of Input data error.

(b) CHEI's projected consumption for 2017-2018 is as follows.

Year	kWh
2017	206 615
2018	207 000

The model filed with these responses has been updated to reflect the suggested correction above.

3-Staff-27

Ref: Exhibit 3/Section 3.1.7/Page 16/Table 4 – HDD and CDD as Reported at Utility Location

OEB staff notes that the “Total” columns for the “HDD and CDD as reported at Utility Location” do not sum correctly. Please reconcile and provide the corrected tables.

Response:

CHEI notes that the total included at Exhibit 3/Section 3.1.7/Page 16/Table 4 – HDD and CDD as Reported at Utility Location is irrelevant to the load forecasting study and should have been omitted from the table.

HDD	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
January	797.10	754.20	979.50	789.20	893.20	831.00	839.90	918.30	894.30	711.00
February	820.00	774.30	711.50	655.80	729.00	671.40	728.50	793.20	957.40	673.00
March	643.00	721.10	598.30	460.70	636.00	460.30	579.60	783.60	726.40	504.00
April	361.10	299.60	334.30	258.10	347.40	363.30	285.50	384.20	345.20	351.00
May	157.30	185.40	181.60	112.30	142.80	96.00	105.70	127.30	90.90	107.00
June	34.20	22.40	50.40	37.60	18.50	0.00	54.10	20.30	40.30	31.00
July	11.80	0.30	13.10	4.50	0.00	0.00	7.70	7.70	7.70	6.00
August	20.10	14.40	26.10	14.70	2.30	8.40	13.40	21.40	7.20	4.00
September	76.00	95.40	106.50	112.00	55.40	127.30	133.20	110.30	46.30	48.00
October	227.50	321.80	355.50	311.00	259.10	243.10	235.80	257.90	311.40	217.00
November	517.00	502.80	417.40	491.60	392.90	541.70	560.80	510.60	417.50	371.00
December	787.70	796.70	759.40	731.40	415.00	680.60	858.20	696.40	490.10	638.00

CDD	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
January	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	3.2	0	0	0	4
May	0	0	2.5	1.6	16.7	21	15.3	8.8	23.5	84
June	17.3	0	3.2	38.2	59.1	70.4	39.4	54.9	22.5	135
July	66.9	60.5	44.9	33.4	137.5	142.2	111.1	62.8	103.8	198
August	65.1	78.9	42.9	150.8	82.3	97.6	57.2	55.8	71.2	213
September	79.3	49.5	82.1	93	32.9	20.6	10.1	21.6	51.7	88
October	25.7	25	5	26.2	1.4	0	0.7	3.1	0	14
November	1.9	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0

3-Staff-28

Ref 1: Exhibit 3/Section 3.1.7/Page 16/Table 4 – HDD and CDD as Reported at Utility Location
Ref 2: Load Forecasting Model – Tab "Input – Adjustments and Variables"

OEB staff notes that at reference 2 above, the CDD were entered beginning in June 2007 whereas the table in reference 1 shows the data beginning in May 2007 (i.e. the numbers have been shifted downwards by one month). Please correct the Cost Allocation Model for this error and provide an updated version in accordance with interrogatory 6-Staff-47.

Response:

The information in the model is correct therefore no change to the cost allocation model was needed. The corrected table is presented at CHEI's response to the previous interrogatory.

3-Staff-29

Ref 1: Exhibit 3/Section 3.4/Pages 54-61/Table 32 – Other Revenue
Ref 2: Chapter 2 Appendices – Tab 2-H

Tab 2-H of the Chapter 2 appendices is reproduced below:

	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
		2014	2014	2015	2016	2017	2018
	USoA Description	Board Approved					
4235	4235-Miscellaneous Service Revenues	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
4225	4225-Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
4082	4082-Retail Services Revenues	-$4,130	-$3,343	-$3,398	-$3,151	-$3,239	-$3,245
4084	4084-Service Transaction Requests (STR) Revenues	$13	-$2	-$2	-$8	-$9	-$10
4210	4210-Rent from Electric Property	$0	-$6,561	-$5,917	-$6,452	-$6,482	-$6,593
4240	4240-Provision for Rate Refunds	$0	$21,935	$20,000	$20,000	$20,000	$20,000
4375	4375-Revenues from Non-Utility Operations	$0	-$31,129	-$9,347	-$3,215	-$75,000	-$30,000
4380	4380-Expenses of Non-Utility Operations	$0	$21,859	$0	$3,215	$75,000	$30,000
4390	4390-Miscellaneous Non-Operating Income	$0	$0	-$7,443	-$12,331	-$5,000	-$5,500
4405	4405-Interest and Dividend Income	$0	-$28,723	-$23,486	-$22,161	-$11,000	-$2,000
	Total	-$30,317	-$48,507	-$55,725	-$53,980	-$36,770	-$28,789

	Specific Service Charges	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
	Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
	Other Distribution/Operating Revenues	-$4,117	$12,029	$10,683	$10,389	$10,271	$10,152
	Other Income or Deductions	$0	-$37,993	-$40,276	-$34,491	-$16,000	-$7,500
	Total	-$24,317	-$48,507	-$55,725	-$53,980	-$36,770	-$28,789

(a) Please provide an explanation for the swings in the amounts in Accounts 4375 and 4380 from 2014 to 2018.
(b) Please explain why for 2014 and 2015 the amounts in the accounts noted in part (a) are not offsetting as seen in 2016-2018.
(c) Please explain why the "total" rows for 2014 Board Approved do not match (i.e. -$30,317 at the top portion of the table and -$24,317 at the bottom portion).

Response:

The revenues and expenses in 4375 and 4380 relate to OPA (IESO) conservation programs, wherein CHEI pays contractors and are reimbursed by IESO. Payments for the years 2014 and 2015 have been audited by the IESO.

b) In 2014 the difference of $ 9 270.10 is an amount received from the OPA(IESO) to cover administration fees.

Similarly, in 2015 the amount of $ 9 347.00 is an amount received from OPA(IESO) to cover the administration fees.

Payments for the years 2014 and 2015 have been audit by IESO.

This is a simple case of error in transposing numbers from the model to the evidence. The total for 2014 should have read 24,317, as shown below. (The information in the table below reflects the May 1 filing)

	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
		2014	2014	2015	2016	2017	2018
	USoA Description	Board					
		Approved					
4235	4235-Miscellaneous Service Revenues	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
4225	4225-Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
4082	4082-Retail Services Revenues	-$4,130	-$3,343	-$3,398	-$3,151	-$3,239	-$3,245
4084	4084-Service Transaction Requests (STR) Revenues	$13	-$2	-$2	-$8	-$9	-$10
4210	4210-Rent from Electric Property	$0	-$6,561	-$5,917	-$6,452	-$6,482	-$6,593
4240	4240-Provision for Rate Refunds	$0	$21,935	$20,000	$20,000	$20,000	$20,000
4375	4375-Revenues from Non-Utility Operations	$0	-$31,129	-$9,347	-$3,215	-$75,000	-$30,000
4380	4380-Expenses of Non-Utility Operations	$0	$21,859	$0	$3,215	$75,000	$30,000
4390	4390-Miscellaneous Non-Operating Income	$0	$0	-$7,443	-$12,331	-$5,000	-$5,500
4405	4405-Interest and Dividend Income	$0	-$28,723	-$23,486	-$22,161	-$11,000	-$2,000
	Total	-$24,317	-$48,507	-$55,724	-$53,981	-$36,771	-$28,789
	Specific Service Charges	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
	Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
	Other Distribution/Operating Revenues	-$4,130	-$3,343	-$3,398	-$3,151	-$3,239	-$3,245
	Other Income or Deductions	$13	-$22,621	-$26,195	-$20,952	-$2,491	$5,897
	Total	-$24,317	-$48,507	-$55,724	-$53,981	-$36,771	-$28,789

3-Staff-30

Ref: Exhibit 3/Section 3.4.3/Page 61 – Proposed Specific Service Charges

Cooperative Hydro Embrun is proposing a change to the MicroFit service charge. Cooperative Hydro Embrun incurs a $10.00 monthly fee per MicroFit meter point from its vendor Utilismart and would like to pass this charge onto its MicroFit customers.

(a) Please confirm if Cooperative Hydro Embrun has provided for this increase in revenue in its 2017 revenue offsets. If not, please make the applicable corrections.
(b) How many customers would be impacted by this change?
(c) How much revenue would the change in the MicroFit rate equate to on an annual basis?

Response:

(a) CHEI did not include this proposed change in its revenue offsets.
(b) Thirteen customers would be impacted by the change (12 as filed + 1 new MicroFit Connection since May1)
(c) The increase in revenues would be $869.00. For 2018 revenues using $5.40/month is $691.20 while revenues for 13 connection using $10/month would be $1560.

3.0 –VECC -12

Reference: Exhibit 3, page 13, Table 3

a) Please confirm that “net of MicroFit” means that the table represents the sum of purchases from Hydro One plus purchases from MicroFit and Fit installations.

Response:

(a) CHE confirms that the table represents the sum of purchases from Hydro One plus purchases from MicroFit installations.

3.0 –VECC -13

Reference: Exhibit 3, page 18
Load Forecast Excel Model, Input Tab

a) It is noted that Customer Count is one of the possible inputs listed in the Input Tab of the model but there is no discussion in the Application as to whether or not Embrun tested this variable. Was customer count tested as a potential explanatory variable? If yes, what were the results and why was it excluded? If not, why not?

b) Please provide the results of two additional regression analyses (i.e., equation and supporting regression statistics):

   i. Include customer count as an additional independent variable, along with those already proposed.

   ii. Include customer count as an additional independent variable along with those already proposed, with the exception of employment which should be excluded.

Response:

(a) Yes, CHEI confirms that the Customer Count variable was tested. Please see part b) for a discussion of the results.

(b)

i. Please find below the results of the Regression analysis. Although including the Customer Count in the study did yield higher results, the utility could not support the negative Coefficient (or correlation), therefore the variable was dropped from the study.

Equation Parameters			95% Confidence/Autocorrelation	
R Squared	0.7975	78.86% of the change in WS can be explained by	1.449	Durbin-Watson Statistic
Adjusted R Squared	0.7886	the change in the 5 independent variables	1.63 - 1.77	Positive autocorrelation detected
Standard Error	175560.5469	to +/- on result of Regression Equation	2.290	Critical F-Statistic - 95% Confidence
F - Statistic	89.8080	Therefore analysis IS Significant	89.62%	Confidence to which analysis holds

Multiple Regression Equation					Independent Analysis			Auto Correlation	Multicollinearity	
	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	DI=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	-443,821.220	931,242.433	-0.477	63.46%						
HDD	1,445.234	69.021	20.939	0.00%	57.06%	946.76	2177336.75	0.35	39.39%	
CDD	4,759.065	492.061	9.672	0.00%	1.78%	-1173.39	2541151.25	0.63	41.27%	
NoD in Month	58,463.865	20,089.291	2.910	0.43%	0.00%	682.01	2489806.25	2.96	3.00%	
Employment	3,933.420	1,317.492	2.986	0.35%	0.36%	-1416.27	3474968.00	0.23	40.66%	
Cust Count	-1,087.781	323.357	-3.364	0.10%	0.23%	-290.00	3080038.00	0.08	34.68%	

ii. Please find below the results of the Regression analysis.

Equation Parameters			95% Confidence/Autocorrelation	
R Squared	0.7817	77.41% of the change in WS can be explained by	1.440	Durbin-Watson Statistic
Adjusted R Squared	0.7741	the change in the 4 independent variables	1.65 - 1.75	Positive autocorrelation detected
Standard Error	181500.4219	to +/- on result of Regression Equation	2.448	Critical F-Statistic - 95% Confidence
F - Statistic	102.9475	Therefore analysis IS Significant	86.12%	Confidence to which analysis holds

Multiple Regression Equation					Independent Analysis			Auto Correlation	Multicollinearity	
	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	Dl=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	952,055.164	832,613.605	1.143	25.52%						
HDD	1,414.390	70.552	20.047	0.00%	57.06%	946.76	2177336.75	0.35	38.54%	
CDD	4,949.493	504.417	9.812	0.00%	1.78%	-1173.39	2541151.25	0.63	40.78%	
NoD in Month	65,117.630	20,640.788	3.155	0.20%	0.00%	682.01	2489806.25	2.96	2.63%	
Cust Count	-534.752	274.010	-1.952	5.34%	0.23%	-290.00	3080038.00	0.08	3.62%	

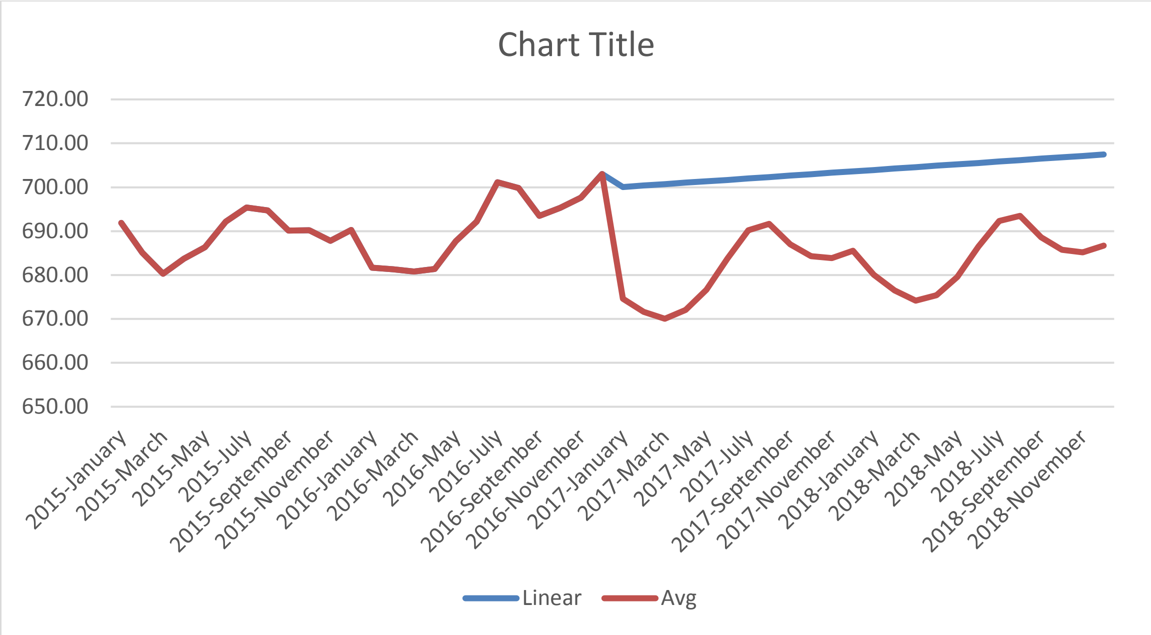
3.0 –VECC -14

Reference: Exhibit 3, page 18
Load Forecast Excel Model, Forecast Tab

a) Please confirm that for the 2017 purchase power forecast the employment variable used in each month was based on the average value for the years 2007-2016. If not, how were the values determined? (Note: The values in the Load Forecast Model are simply numerical inputs)
b) Please confirm that for the 2018 purchase power forecast the employment variable used in each month was based on the average value for the years 2008-2017. If not, how were the values determined? (Note: The values in the Load Forecast Model are simply numerical inputs)
c) Please provide the rationale for the approach used in parts (a) and (b).
d) Using the data in Table 5 and trend analysis please project the employment levels in each month for 2017 and 2018 and compare the results with the values used in Embrun's forecast.
e) Is Embrun aware of any forecasts of employment for the Ottawa Region? If so, please provide.

Response:

(a) For all variables except "employment," the utility used an average. For the employment, the utility uses a linear forecasting method as an average would yield incorrect projections for 2017-2018.
(b) See response to a)
(c) The utility found that the linear approach reflected a more accurate projection for 2017-2018 than the use of the average which showed a decrease going forward.



(d) CHEI is not aware of any forecasts of employment for the Ottawa Region that would apply to its service area.

3.0 –VECC -15

Reference: Exhibit 3, pages 15-16
Load Forecast Excel Model, Forecast Tab

a) The HDD values used for 2017 appear to be based on an average of 2007-2016. However, the values used for 2018 are different (and hard coded inputs). Please explain the basis for the 2018 values used.
b) The CDD values used for 2018 appear not be based on the average for the years 2007-2016 as the Application states (page 15), but rather on an average of the values for 2008-2017 plus the 10 year average (2007-2016) average. Please explain why.

Response:

a) In testing the regression analysis, the formulas were inadvertently overwritten with hardcoded inputs. CHEI has rectified the issue. The effects of the correction are shown below.

The table 1) below shows the final load forecast as filed

Final Load Forecast Results

	Year	2014	2015	2016	2017	2018	2018 CDM Adjusted
Residential	Cust/Conn	1,800	1,847	1,927	2,040	2,100	2,100
	kWh	19,479,913	19,377,540	19,268,403	21,046,900	21,676,646	21,616,344
	kW						
General Service < 50 kW	Cust/Conn	159	165	163	168	172	172
	kWh	4,701,954	4,594,197	4,538,610	4,941,575	5,057,633	5,043,563
	kW						
General Service > 50 to 4999 kW	Cust/Conn	11	11	11	9	9	9
	kWh	4,346,251	4,316,369	4,274,953	3,657,936	2,835,388	2,827,501
	kW	12,214	12,238	12,169	12,701	12,772	12,736
USL	Cust/Conn	19	19	18	17	17	17
	kWh	89,075	94,284	94,284	82,356	82,356	82,127
	kW	-	-	-	-	-	-
Street Lighting	Cust/Conn	409	430	505	517	530	530
	kWh	359,464	373,173	376,348	385,594	395,068	393,969
	kW	1,003	1,050	576	590	605	603
Total	**Cust/Conn**	**2,398**	**2,471**	**2,623**	**2,751**	**2,828**	**2,828**
	kWh	**28,976,657**	**28,755,563**	**28,552,598**	**30,114,361**	**30,047,092**	**29,963,504**
	kW	**13,217**	**13,288**	**12,745**	**13,291**	**13,377**	**13,339**

Table 2 below show the load forecast with the correctedformulas.

Final Load Forecast Results							
	Year	2014	2015	2016	2017	2018	2018 CDM Adjusted
Residential	Cust/Conn	1,800	1,847	1,927	2,040	2,100	2,100
	kWh	19,479,913	19,377,540	19,268,403	21,046,900	21,674,374	21,614,037
	kW						
General Service < 50 kW	Cust/Conn	159	165	163	168	172	172
	kWh	4,701,954	4,594,197	4,538,610	4,924,274	5,039,913	5,025,884
	kW						
General Service > 50 to 4999 kW	Cust/Conn	11	11	11	9	9	9
	kWh	4,346,251	4,316,369	4,274,953	3,657,936	2,835,388	2,827,495
	kW	12,214	12,238	12,169	12,701	12,725	12,690
USL	Cust/Conn	19	19	18	17	17	17
	kWh	89,075	94,284	94,284	82,356	82,356	82,127
	kW	-	-	-	-	-	-
Street Lighting	Cust/Conn	409	430	505	517	530	530
	kWh	359,464	373,173	376,348	385,594	395,068	393,968
	kW	1,003	1,050	576	590	605	603
Total	**Cust/Conn**	**2,398**	**2,471**	**2,623**	**2,751**	**2,828**	**2,828**
	kWh	**28,976,657**	**28,755,563**	**28,552,598**	**30,097,060**	**30,027,100**	**29,943,511**
	kW	**13,217**	**13,288**	**12,745**	**13,291**	**13,330**	**13,293**

The model filed along with these responses reflect the corrected formulas.

b) Correct. The utility uses a 10-year historical average counting backward from the year in question. Therefore, for 2018, CHEI used 2008-2017. Using 2007-2016 would yield the same results as 2017 which in CHEI's view would be incorrect as the forecast for 2018 should reflect exponential trend.

3.0 –VECC -16

Reference: Exhibit 3, page 23

a) In Table 10 the ten year values and 20 year values are exactly the same – please review and correct as necessary.

Response:

(a) Table 10 is replicated below. The 2018 weather normalized wholesale use a 10-year average of HDD/CDD at columns A&B and use a 20-year average of HDD/CDD at columns C&D. (CHEI notes that the exercise is done for the test year only as 2018 rate are determined on the basis of the 2018 load forecast).

(b)

	A	B	C	D
Date	Weather Normalized 10Year	Yearly Total 10Year	Weather Normalized 20Year	Yearly Total 210Year
2017-January	3142979.43		3142979.43	
2017-February	2840325.17		2840325.17	
2017-March	2820641.02		2820641.02	
2017-April	2368393.81		2368393.81	
2017-May	2222971.52		2222971.52	
2017-June	2140944.34		2140944.34	
2017-July	2407827.06		2407827.06	
2017-August	2397444.47		2397444.47	
2017-September	2267720.74		2267720.74	
2017-October	2394416.66		2394416.66	
2017-November	2565679.06		2565679.06	
2017-December	2906949.88	30476293	2906949.88	30476293
2018-January	3154453.34		3169199.84	
2018-February	2837336.59		2823838.78	
2018-March	2821527.57		2832634.68	
2018-April	2370132.65		2365210.80	
2018-May	2232510.42		2249947.60	
2018-June	2158053.64		2162125.47	
2018-July	2425716.52		2426893.43	
2018-August	2413902.59		2415026.30	
2018-September	2263147.78		2257627.01	
2018-October	2399231.13		2415828.85	
2018-November	2563974.56		2568799.68	
2018-December	2895653.77	30535640	2959106.38	30646238

3.0 –VECC -17

Reference: Exhibit 3, pages 24-25

a) Are the customer/connection counts shown in Table 11 year-end or average annual values?
b) Please provide the actual customer/connection count by class as of June 30, 2017.
c) Please provide the customer/connection counts by class for the most recent month available.

Response:

(a) The customer/connection counts shown in Table 11 are average annual values as of February 2015.

(b) Below are the actual customer/connection counts by class as of June 30, 2017

Class	Customers
Residential	1972
Below 50 kW	164
Over 50 Kw	9
USL	17
Streetlights (Connections)	556

(c) Below are the actual customer/connection counts by class as of September 30, 2017

Class	Customers
Residential	2007
Below 50 Kw	164
Over 50 Kw	9
USL	17
Streetlights (Connections)	556

3.0 –VECC -18

Reference: Exhibit 3, pages 24-25
Load Forecast Excel Model, Input-Customer Data Tab

a) Please explain the following statement “in CHEI’s case the MicroFit related consumption was removed from the Wholesale Purchases” and indicate exactly what the related adjustments were and where they are reflected in the Load Forecast model.
b) In the Load Forecast model it appears that, for the Residential, GS<50 and GS>50 classes, the geomean growth rate was applied to the 2015 customer count (as opposed to the 2016 value) in order to project 2017. Please review and correct the 2017 and 2018 values as required.
c) Please explain the basis for the subsequent adjustments made to the forecast customer counts for each of the Residential, GS<50 and GS>50 classes.

Response:

(a) CHEI removed the consumption related to the MicroFit for the regression analysis only. The idea behind removing the consumption related to MicroFit is to remove the “known adjustments” from the regression equation. This is a form of statistical process control where CHEI is trying to detect events that don’t fit a model. CHEI notes that this methodology has been approved in numerous applications.

(b) The error was corrected. The revised model is being filed along with these responses.

(c) When the application was filed, CHEI was aware that a subdivision was waiting for 114 new services to be connected. The utility confirms that it is on track to having 2040 customers in service by end of 2017. The utility also knew that several GS>50 customers were going to move to the GS<50 class and that 2 new services are anticipated.

3.0 –VECC -19

Reference: Exhibit 3, page 27

a) In Table 12, please confirm that the column titled “Weather Normalized” is the ratio of actual Residential sales over actual Wholesale Purchases and does not involve any “weather normalization”.
b) In Table 12, please confirm that the column “Weather Normal” is the result of multiply the ratio (per part (a)) by the predicted Wholesale Purchases based on actual HDD and CDD values and, as a result, does not involve any “weather normalization”.
c) Using Residential as an example, please explain the revisions to the forecast made due to the “Load corrected based on utility input” (i.e., the second table on the page).

Response:

(a) CHEI confirms that its load has been normalized to reflect normal weather as per Hydro One’s weather normalization methodology (http://cf.oeb.ca/documents/cases/EB-2005-0317/phase3/jun15/handout-weathernormalization-honi.pdf) as a comparison. (excerpt of Hydro One’s document process is shown below)

- *An equation relating daily energy and daily weather conditions is developed using the latest 4 years of data. This time frame allows the analysis to reflect the most recent load mix while having sufficient data to quantify its weather sensitivity. For example, the share of space cooling energy relative to total energy has increased rapidly over the past decade; using too long a time series of historical data may lead to significant under-estimation of the weather sensitivity of load in the summer.*
- *To better isolate the impact of weather, systematic changes in daily loads are identified and filtered out before the regression analysis begins. The systematic effects removed include growth trends, cyclical variations, day-of-the-week effects and holiday effects. The objective is to filter the data to weather-related load and noise (random effect).*
- *Different types of weather data are used in the analysis. For winter loads, weather data include temperature, wind speed and cloud opacity. For summer loads, weather data include temperature, humidity and cloud opacity. Because weather effects cumulate over several days, the temperatures for the current day as well as the previous 3 or 4 days are also used as explanatory variables in the model. The relationship between energy and weather may be represented by the following function:*

(1) Weather- Related Energy = f (Weather Conditions) + Random Term

where the random term reflects any remaining variations that are not explained systematically by weather. The random term is assumed to be distributed independently, identically and normally with mean equals to zero.

- *The coefficients from Equation (1) are estimated using the most recent 4 years of daily load and weather data. These coefficients indicate the sensitivity of load in the service territory relative to today's temperature, yesterday's temperature and all other weather variables included in the equation. The estimated coefficients are multiplied by the actual weather data for the corresponding weather variable in the equation to determine the estimated weather-related energy for the day. This process is repeated for each day of the period for which weather- correction is performed.*

(2) Estimated Weather-Related Energy = f (Actual Weather Conditions and Estimated Coefficients)

- *Equation (2) is used to determine what "normal" weather-related loads would be for each day of the year given the current mix of weather-sensitive loads in that service territory. This is done by running the equation with each of the last 31 years of daily weather data for that day plus the seven days on either side of it. The average of the estimated weather-related loads for the 15 days times 31 years (465 observations) is deemed to be the "normal" weather-related energy for that day. Using 31 years of weather history is considered adequate to approximate normal weather.*

c) CHEI has calculated a per/customer consumption and has added the load to the calculated 10-year average. This logic was also applied to the GS classes.

3.0 –VECC -20

Reference: Exhibit 3, page 29
Load Forecast Model, Bridge&Test Year Class Forecast Tab

a) In Table 14, please explain why the GS>50 forecast for 2018 is significantly less than that for 2017 when the customer count is the same in both years. In reviewing the Load Forecast Model it appears that the customer loss in 2017 has been double counted in 2018.

Response:

(a) CHEI acknowledges that there was an error in the formula and that the error has been rectified in the version of the model filed with these IR responses.

GS>50						
Year	New Customer	Per Customer Weather Normalized	Added Load			Total
2017	-2	411,274	-822,547			**3,657,936**
2018	0	417,585	0			**3,657,936**

3.0 –VECC -21

Reference: Exhibit 3, pages 34-39

a) Please provide a copy of Embrun's approved CDM Plan.
b) Please confirm that, based on Embrun's approved CDM Plan the expected energy savings from 2016, 2017 and 2018 CDM programs are 254 MWh, 278 MWh and 434 MWh respectively.
c) Please provide a copy of Embrun's verified 2016 CDM Results (the excel version).
d) Please confirm that the verified results from 2016 CDM programs persisting in 2018 is 730,807 kWh.
e) Please reconcile the preceding values with the 2018 CDM adjustment proposed in the Application

Response:

(a) Attached is the current approved CDM plan.
(b) The expected energy savings have been updated. The 2016 savings were changed to reflect the 2016 verified savings, 2017 was updated to reflect projections, and 2018 as well.
  - 2016 - 670.4 MWh
  - 2017 - 297.8 MWh
  - 2018 - 254.8 MWh
(c) The Excel version of CHEI's 2016 Results have been filed in conjunction with these responses.
(d) Confirmed.
(e) The 2016 final CDM results were not yet available at the time of the filing. The CDM adjustments in the Load Forecasting model have been updated to reflect this new information.

3.0 –VECC -22

Reference: Exhibit 3, page 40

a) Please explain how the total LRAMVA baseline value of 2,084,706 kWh was derived.

Response:

(a) The 2015 verified results were incorrect (the OEB defaults were used instead). The revised models include verified results for 2015 and newly updated verified results from 2016.

3.0 –VECC -23

Reference: Exhibit 3, page 57

a) In what account are the revenues from the MicroFit service charges recorded and what were the revenues for 2016?
b) In what account are the revenues from SSS Admin Fees recorded and what were the revenues in 2016?

Response:

(a) & (b) See table below

	2016		
Service	**Quantity**	**Rate**	**Total**
Standard Supply Service -- Administrative Charge	24615	$0.25	$6,153.74
Misc. Revenue - MicroFit service charge	128	$5.40	$691.20

Exhibit 4 – Operating Expenses

4-Staff-31

Ref 1: Exhibit 4
Ref 2: Chapter 2 Appendices

Please update the following tabs in the Chapter 2 appendices for actuals to date:

1. Tab 2-JA – OM&A Summary Analysis (Page 8 of Exhibit 4)
2. Tab 2-JB – OM&A Cost Drivers (Page 9 of Exhibit 4) N/A
3. Tab 2-JC – OM&A Programs (Page 22 of Exhibit 4)
4. Tab 2-K – Employee Costs (Page 34 of Exhibit 4)
5. Tab 2-L – OM&A Cost per FTE (Page 17 of Exhibit 4)

Reporting Basis						
	Last Rebasing Year (2014 Board-Approved)	**Last Rebasing Year (2014 Actuals)**	**2015 Actuals**	**2016 Actuals**	**2017 Actuals 9 months**	**2018 Test Year**
Operations	$20,900	$28,851	$39,764	$34,209	$27,304	$37,769
Maintenance	$40,300	$44,655	$26,251	$46,223	$41,544	$56,215
Subtotal	**$61,200**	**$73,506**	**$66,014**	**$80,432**	**$68,848**	**$93,984**
%Change (year over year)		20.1%	-10.2%	21.8%	-14.4%	36.5%
%Change (Test Year vs Last Rebasing Year - Actual)						53.6%
Billing and Collecting	$170,174	$166,891	$210,565	$177,779	$127,518	$209,970
Community Relations	$4,000	$6,982	$8,363	$7,863	$6,269	$7,875
Administrative and General+LEAP	$320,905	$321,703	$328,131	$334,952	$283,300	$410,142
Subtotal	**$495,079**	**$495,575**	**$547,058**	**$520,594**	**$417,087**	**$627,987**
%Change (year over year)		0.1%	10.4%	-4.8%	-19.9%	50.6%
%Change (Test Year vs Last Rebasing Year - Actual)						26.8%
Total	**$556,279**	**$569,081**	**$613,072**	**$601,025**	**$485,935**	**$721,971**
%Change (year over year)		2.3%	7.7%	-2.0%	-19.1%	48.6%

	Last Rebasing	2014 Last Rebasing	2015 Actuals	2016 Actuals	2017 Actuals	2018 Test Year

	Year (2014 Board-Approved)	Year (2014 Actuals)			9 months	
Operations	$20,900	$28,851	$39,764	$34,209	$27,304	$37,769
Maintenance	$40,300	$44,655	$26,251	$46,223	$41,544	$56,215
Billing and Collecting	$170,174	$166,891	$210,565	$177,779	$127,518	$209,970
Community Relations	$4,000	$6,982	$8,363	$7,863	$6,269	$7,875
Administrative and General	$320,905	$321,703	$328,131	$334,952	$283,300	$410,142
Total	$556,279	$569,081	$613,072	$601,025	$485,935	$721,971
%Change (year over year)		2.3%	7.7%	-2.0%	-19.1%	48.6%

Table 2. CHEI believes an updated Cost Driver showing 9 months of actuals would create misleading false variances therefore CHEI respectfully declines to provide this information.

Table 3.

						Test Year Versus 2014 Actual	Test Year Versus Most Current Actuals
Reporting Basis	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP		
Programs	2014	2015	2016	2017	2018	Variance ($)	Variance ($)
Customer Focus							
Customer Service, Mailing Costs, Billing and Collections	$213,226	$255,933	$218,476	$161,259	$249,104	$35,878	$30,628
Bad Debts	$5,473	$5,001	$4,960	$5,000	$10,000	$4,527	$5,040
Service Locates	$15,891	$25,525	$19,442	$15,355	$21,420	$5,529	$1,978
Sub-Total	$234,589	$286,459	$242,877	$181,614	$280,524	$45,935	$37,647
Operational Effectiveness							
Administrative Effectiveness	$208,691	$214,736	$219,075	$176,765	$244,771	$36,080	$25,696
Regulation Consultant-Services	$37,868	$42,412	$45,071	$41,891	$49,691	$11,823	$4,620
Distribution Operating & Maintenance	$48,100	$29,358	$50,315	$45,688	$61,115	$13,016	$10,800
Sub-Total	$294,658	$286,506	$314,461	$264,344	$355,577	$60,919	$41,116
Public and Regulatory Responsiveness							
Regulatory & Compliance	$35,942	$36,194	$39,812	$34,599	$81,800	$45,858	$41,988
Electrical safety Authority	$1,892	$1,913	$1,875	$1,898	$2,070	$178	$195
Sub-Total	$37,834	$38,107	$41,687	$36,497	$83,870	$46,036	$42,183
Miscellaneous							
Donation Leap	$2,000	$2,000	$2,000	$2,000	$2,000	$0	$0
Sub-Total	$2,000	$2,000	$2,000	$2,000	$2,000	$0	$0
TOTAL OM&A	$569,081	$613,072	$601,025	$484,455	$721,971	$152,890	$120,946

Table 4.

	2014	2015	2016	2017	2018
Number of Employees (FTEs including Part-Time)[1]					
Management (including executive)	1	1	1	1	1
Non-Management (union and non-union)	2	2	2	2	2
Total	3	3	3	3	3
Total Salary and Wages including ovetime and incentive pay					
Management (including executive)	$188,050.43	$213,055.37	$233,873.83	$148,355.35	$225,000.00
Non-Management (union and non-union)	$0.00				
Total	$188,050.43	$213,055.37	$233,873.83	$148,355.35	$225,000.00
Total Benefits (Current + Accrued) -					
Management (including executive)	$30,053.21	$30,752.94	$26,894.33	$15,477.62	$31,650.00
Non-Management (union and non-union)	$0.00				
Total	$30,053.21	$30,752.94	$26,894.33	$15,477.62	$31,650.00
Total Compensation (Salary, Wages, & Benefits)					
Management (including executive)	$218,103.64	$243,808.31	$260,768.16	$163,832.97	$256,650.00
Non-Management (union and non-union)	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$218,103.64	$243,808.31	$260,768.16	$163,832.97	$256,650.00

Table 5.

	2014 Board Approved	2014	2015	2016	2017 Actual (9 months)	2018
OM&A Costs						
O&M	$61,200.00	$73,505.84	$66,014.49	$80,431.59	$68,848.00	$93,984.00
Admin Expenses	$320,905.00	$321,703.08	$328,130.52	$334,951.92	$283,300.00	$410,142.00
Total Recoverable OM&A from Appendix 2-JB [5]	$382,105.00	$395,208.92	$394,145.01	$415,383.51	$352,148.00	$504,126.00
Number of Customers [2,4]	2227	1985	2078	2137	2180	2281
Number of FTEs [3,4]	3	3	3	3	3	3
Customers/FTEs	742.33	661.67	692.67	712.33	726.67	760.37
OM&A cost per customer						
O&M per customer	27	37	32	38	32	41
Admin per customer	144	162	158	157	130	180
Total OM&A per customer	172	199	190	194	162	221
OM&A cost per FTE						
O&M per FTE	20,400	24,502	22,005	26,811	22,949	31,328
Admin per FTE	106,968	107,234	109,377	111,651	94,433	136,714
Total OM&A per FTE	127,368	131,736	131,382	138,461	117,383	168,042

4-Staff-32

Ref: Chapter 2 Appendices, Tab 2-JA

The proposed OM&A costs in 2018 of $721,971 represent an increase of $152,890 or 27% over the 2014 actual OM&A.

(a) Please identify any customer engagement relating specifically to the increase in OM&A that supports the increases proposed in this application.

(b) Please identify what if any improvements in services and outcomes the applicant's customers will experience in 2018 and during the subsequent IRM term as a result of increasing the provision for OM&A at the rate indicated.

(c) Please identify any initiatives considered and/or undertaken by Cooperative Hydro Embrun, including any analysis conducted, to optimize plans and activities from a cost perspective.

Response:

(a) Please see CHEI's response to section b) of 1-Staff-3 and section e) of 1-Staff 10.

(b) The costs included in the Test Year are the minimum costs required to operate the utility in the most cost-efficient manner possible. The utility has not included any discretionary costs that may or may not provide value increases in outcomes and services in future years. As explained in Section 1.3 of the Business Plan, CHEI plans to achieve its strategic goals by setting and meeting the following objectives:

- Improve grid reliability.
- Create a service-based utility whose primary goal is to exceed customers' expectations at a
- reasonable cost.
- Promote the long-term, efficient provision of utility services consistent with OEB policy.
- Work with other utilities in the promotion of both efficient and sustainable environment.
- Operate effectively with the staff currently in place.
- Reduce operational costs where and when possible.
- Develop and adopt an actionable plan to improve customer experience.

CHEI also notes that many of its costs are non-discretionary and out of the utility's control. i.e. increase in locates, new underground service, increase in bad debt, regulatory costs etc.

(c) CHEI has not and does not intend to conduct expensive or time-consuming analysis on optimizing plans and activities from a cost perspective. Please see the response to interrogatory 1-Staff 11 for a discussion of the criteria or strategy used to determine which solutions are the most cost-effective for Cooperative Hydro Embrun and its customers.

4-Staff-33

Ref: Exhibit 4/Section 4.1.1/Page 6 - Overview

	2014 Board Approved	2018	Diff
Operations	$20,900	$37,769	$16,869
Maintenance	$40,300	$56,215	$15,915
Billing and Collecting	$170,174	$209,970	$39,796
Community Relations	$4,000	$7,875	$3,875
Administrative and General	$320,905	$410,142	$89,237
Total	**$556,279**	**$721,971**	**$165,692**
%Change (year over year)			29.79%

Cooperative Hydro Embrun notes that the majority of the variance in OM&A between the 2014 OEB-approved and 2018 test year is attributable to an increase in administrative costs. Please provide a breakdown of what the $89k increase consists of (i.e. what are the discrete items).

Response:

Please see the discussion at Exhibit 4, page 10. Most of the increase is attributable to Regulatory Expenses (38k), Management Salaries and Expenses(11K) and the remainder is a total of variances less than $5K (approximately 20K/year) which is attributable to the increase in cost of living.

4-Staff-34

Ref: Exhibit 4/Section 4.2.1/Page 10 – Summary of Cost Drivers

Cooperative Hydro Embrun included a one-time severance pay ($45k) after terminating an employee and an increase in salaries ($7k) for 2 customer service representatives in Account 5315 – Customer Billing.

Please explain the rationale for including these costs in this account.

Response:

As per the Accounting Procedure Handbook, which states "*This account shall include all costs related to the billing of customer accounts. These costs shall include salaries and wages with payroll burden, stationery, postage, delivery expense and the charges for contract billing performed by other parties*", CHEI deemed it accurate to post increases in wages and severance pay to the same account.

4-Staff-35

Ref: Exhibit 4/Section 4.4/Page 35 – Workforce Planning and Compensation Strategy

Cooperative Hydro Embrun notes that it does not use specific benchmarking studies to determine salary ranges, however uses neighbouring utilities' salaries a guideline. In addition, when compared to the Sunshine List, its salaries and increases over the last 4 years are well below those published in the Sunshine List.

(a) Does Cooperative Hydro Embrun plan on undertaking in the future any benchmarking analysis to comparable utilities?
(b) Please explain why Cooperative Hydro Embrun believes the Sunshine List is an appropriate comparable benchmark for its salary ranges.

Response:

a) The utility does not anticipate undertaking compensation benchmarking analysis as these types of analysis are generally expensive and the utility cannot justify such discretionary costs. Going forward, the utility will continue to monitor for benchmarking results that are public and accessible.
b) The evidence does not indicate that CHEI uses the Sunshine List as a benchmark for its salary ranges. Rather, as stated at Exhibit 4, page 35:

> CHEI does not use specific benchmarking studies to determine salary ranges. CHEI and its shareholder are aware of the salary ranges in neighbouring utilities and *use the neighbouring salaries as a guideline*. [emphasis added]

The evidence further states that:

> Periodically, the utility's Board of Director along with management input will readjust employee salary to be in line with it neighbouring cohorts, however, as a rule, the utility tries to apply the inflation factor of 2% to salaries and wages.

The evidence describes CHEI's use of the Sunshine list data to determine the average increases awarded to those entities and compare its own annual increase, however, as noted above CHEI does not apply annual increases based on the Sunshine List results.

4-Staff-36

Ref 1: Exhibit 4/Section 4.4/Page 35 – Workforce Planning and Compensation Strategy
Ref 2: Chapter 2 Appendices – Tab 2-K

Reference 2 is reproduced below:

	Last Rebasing Year - 2014- Actual	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time)[1]					
Management (including executive)	1	1	1	1	1
Non-Management (union and non-union)	2	2	2	2	2
Total	3	3	3	3	3
Total Salary and Wages including ovetime and incentive pay					
Management (including executive)	$ 188,050	$ 213,055	$ 233,874	$ 215,007	$ 225,000
Non-Management (union and non-union)	$ -				
Total	$ 188,050	$ 213,055	$ 233,874	$ 215,007	$ 225,000
Total Benefits (Current + Accrued) [2]					
Management (including executive)	$ 30,053	$ 30,753	$ 26,894	$ 30,136	$ 31,650
Non-Management (union and non-union)	$ -				
Total	$ 30,053	$ 30,753	$ 26,894	$ 30,136	$ 31,650
Total Compensation (Salary, Wages, & Benefits)					
Management (including executive)	$ 218,104	$ 243,808	$ 260,768	$ 245,143	$ 256,650
Non-Management (union and non-union)	$ -	$ -	$ -	$ -	$ -
Total	$ 218,104	$ 243,808	$ 260,768	$ 245,143	$ 256,650

At reference 1, Cooperative Hydro Embrun notes that periodically the Board of Directors along with management input re-adjusts employee salary to be in line with neighbouring cohorts, however as a rule, the utility tries to apply a 2% inflation factor to salaries and wages.

(a) Please explain the varying amounts for total salary and wages including overtime and incentive pay in 2015 to 2017 (i.e. $213k in 2015 up to $233k in 2016 and back down to $215k in 2017).

(b) Please confirm if Cooperative Hydro Embrun agrees with the year over year increases/decreases below calculated by OEB staff:

	2014 Approved	2014 Actual	2015	2016	2017	2018
Total OM&A	$556,279	$569,081	$613,072	$601,025	$651,616	$721,971
% increase per year	-	2.3%	8%	-2%	8%	11%

(c) Please explain the increases given that Cooperative Hydro Embrun tries to apply a 2% inflation factor to salaries and wages. Are these increases the result of overtime, vacation paid out etc.?

Response:

a) The Tables below detail 2014-2015 -2016-2017 total salary and wages variances as shown in Reference 2.

2014

Salary	Vacation not taken	Incentive	Total
$ 187,192.00	$ 858.00		$ 188 050.00

2015

Salary	Vacation not taken	4 % Vacation Pay	Severance Pay	Incentive	Total
$ 186,107.00	$ 2,188.00	$ 1,685.00	$ 12,000.00	$ 10,875.00	$ 213,055.00

2016

Salary	Vacation not taken	Severance Pay	Incentive	Total
$ 194,930.00	$ 6,915.00	$ 28,106.00	$ 2,000.00	$ 233,874.00

2017 (May 1st Submit Budget)

Salary	Vacation not taken to date	Severance Pay	Incentive	Total
$ 204,005.00	$ 10,171.00	-	$ 1,000.00	$ 215,000.00

b) CHEI notes that the year over year increases as calculated by Board staff relate to total OM&A. As calculated, the year over year percentage changes are correct.

c) Please see the response to part a), above. CHEI notes that its evidence states that “the utility tries to apply the inflation factor of 2% to salaries and wages”. The percentages calculated by Board staff relate to CHEI’s total OM&A costs, of which salaries and wages are less than 50%. Changes in total OM&A year over year are the result of many factors beyond inflation, such as known cost increases, growth, legislative and regulatory change, etc. CHEI believes that it would be inappropriate to comment on the proposed comparison.

4-Staff-37

Ref: Exhibit 4/Section 4.6.3/Page 45 – Regulatory Costs

	Worst Case
AESI (DSP)	$25,000.00
BDO (PILs + DVAs + IRs)	$10,000.00
Production & Submission (Print)	$1,000.00
Public Notice (OEB)	$1,000.00
Legal - Review, IR, Settlement, DRO	$32,000.00
Legal - Oral hearing	$45,000.00
Intervenor costs	$40,000.00
Community Meeting	$10,000.00
Total Cost of Service Filing costs	$164,000.00

Cooperative Hydro Embrun indicates that the regulatory costs proposed in the application include provision for legal fees related to an Oral Hearing if the parties are unable to reach a full settlement and includes provision for up to 2 intervenors. Cooperative Hydro Embrun proposes to remove these costs if the application is dealt with via written hearing or parties reach a full settlement and if only one intervenor gets involved in the application.

Please provide a breakdown by category of the costs proposed to be removed given that this proceeding has one approved intervenor. Please also provide two tables with the proposed costs to be removed if there is 1) a full settlement, and 2) a partial settlement.

Response:

CHEI is unable to provide the requested breakdown at this time. While it could reasonably be expected that certain budgeted costs may decrease in the event that a full settlement is reached, it is not clear at this time the extent that these may be offset by cost increases already incurred.

Since the preparation of the regulatory budget the process has resulted in certain unanticipated costs, the full impact of which is not yet known. The utility notes that it also incurred unexpected costs as a result of the Community Meeting such as printing costs for the billing insert and posters, requirements that were not communicated to the utility until weeks prior to the Community Meeting. In addition, at the time of the filing, the utility was not aware of the need for a presentation day which is expected to result in additional travel and accommodation costs which were not included in the regulatory projections.

4-Staff-38

Ref: Exhibit 4/Section 4.10/Page 60 – Non-Recoverable and Disallowed Expenses

OEB staff is unable to find a reference to property taxes applicable to Cooperative Hydro Embrun.

(a) Please confirm if Cooperative Hydro Embrun pays property taxes.

(b) If Cooperative Hydro Embrun does pay property taxes, please provide the most recent OEB-Approved, historical years 2014-2016, the 2017 bridge year and the 2018 test year amounts.

Response:

a) Confirmed. The costs are included in account 5012.

b)

Years	Property Taxes & Payment in Lieu Property Taxes
2014	$ 1 365.17
2015	$ 1 449.78
2016	$ 1 306.48
2017	$ 1 220.14

4-Staff-39

Ref: Exhibit 4/Section 4.12.2/Pages 64-66 - LRAMVA

OEB staff notes that if the OEB approves a distributor’s account balances on a final basis, any adjustments made to prior years by the IESO are not recoverable.

Is Cooperative Hydro Embrun expecting any retroactive adjustments from the IESO to its savings?

Response:

CHEI has proposed to dispose of its audited 2015 LRAMVA based on the IESO final report for 2015, in accordance with OEB policy. Retroactive adjustments to the 2015 final results by the IESO are beyond the utility’s control. CHEI is of the opinion that, under these circumstances, prior year adjustments should be recoverable by the utility.

4-Staff-40

Ref: Tab 1 of 2018 LRAMVA Work Form (May 1, 2017)

Cooperative Hydro Embrun applied for a debit balance of $10,951 in lost revenues associated with new CDM programs savings between 2013 and 2015, and persisting savings from 2013 to 2015. Of this original amount, it includes a credit balance of $3,855 to indicate the 2011 and 2012 LRAMVA amounts cleared in the 2014 COS application (EB-2013-0122).

As noted in Cooperative Hydro Embrun's 2018 COS application, the LRAMVA request pertains to disposing of balances related to 2013, 2014 and 2015.

(a) Please provide rationale for including a credit balance of $3,855 for 2011 and 2012 amounts, as the current disposition is related to seeking recovery for 2013-2015 amounts.

(b) As past approved amounts do not need to be included in the balance of the current LRAMVA disposition, please confirm appropriateness of removing the credit amount of $3,855 from Table 1 (cell K27).

Response:

(a) CHEI notes that the past approved balance was included in the calculation in error.

(b) Confirmed. The revised LRAMVA Summary is shown below

Description	LRAMVA Previously Claimed	Residential	General Service < 50 kW	General Service > 50 to 4999 kW	Unmetered Scattered Load	Street Lighting	Total
		kWh	kWh	kW	kWh	kW	
2011 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2012 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2013 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2014 Actuals	☐	$1,183.45	$837.33	$0.00	$0.00	$0.00	$2,020.78
2014 Forecast		($3,287.14)	($1,094.23)	($759.83)	($12.81)	($90.77)	($5,244.79)
Amount Cleared							
2015 Actuals	☐	$2,681.97	$537.07	$0.00	$0.00	$0.00	$3,219.04
2015 Forecast		($3,520.09)	($917.32)	($589.11)	($6.41)	($107.42)	($5,140.34)
Amount Cleared							
2016 Actuals		$7,037.64	$6,462.15	$0.00	$0.00	$0.00	$13,499.79
2016 Forecast		($3,571.85)	($930.43)	($597.64)	($6.53)	($108.98)	($5,215.43)
Amount Cleared							
Carrying Charges		($58.44)	$14.14	($35.05)	($0.52)	($4.97)	($84.83)
Total LRAMVA Balance		**$466**	**$4,909**	**-$1,982**	**-$26**	**-$312**	**$3,054**

Note: LDC to make note of assumptions included above, if any

4-Staff-41

Ref: Tab 2 of 2018 LRAMVA Work Form (May 1, 2017)

In the LRAMVA work form, Cooperative Hydro Embrun included the following amounts for forecast CDM savings used for comparison against actual program results: 38,800 kWh in 2013, and 38,800 kWh in 2014, and 0 kWh in 2015.

(a) Please confirm the LRAMVA threshold approved in the 2010 COS application. Please also provide the rate class specific breakdown of the 2010 LRAMVA threshold, as it appears the 2010 LRAMVA threshold amount was not reflected in Tab 2.

(b) Please update in Table 2 of your application using the approved LRAMVA threshold from the 2010 cost of service application in the calculation of 2013 LRAMVA amounts.

Response:

(a) CHEI confirms that no LRAMVA threshold amount was approved in its 2010 application.

(b) Please see response to part a), above.

4-Staff-42

Ref: Tab 2 of 2018 LRAMVA Work Form (May 1, 2017); 2014 DRO Load Forecast Worksheet (revision Jan 10, 2014)

In Cooperative Hydro Embrun's 2014 Draft Rate Order in the 2014 cost of service application, the approved LRAMVA threshold was 388,471 kWh in 2014.
As indicated in the filing requirements and CDM Guidelines, the LRAMVA threshold approved as part of a distributor's most recent cost of service application is to be used as part of the LRAMVA calculation.

(a) Please discuss why Cooperative Hydro Embrun has not used the LRAMVA threshold of 388,471 kWh approved in its 2014 CoS to calculate the following LRAMVA amounts:
  i. 2014
  ii. 2015

(b) Please discuss why Cooperative Hydro Embrun has used the following LRAMVA thresholds:
  i. 2014 – 38,800 kWh
  ii. 2015 – 0 kWh

(c) Please update your application using the approved LRAMVA threshold of 388,471 kWh in the calculation of 2014 and 2015 LRAMVA amounts.

Response:

The issues raised in this specific interrogatory have been rectified in the 2018 LRAMVA model filed in conjunction with these responses. CHEI notes that it had inadvertently used the LRAMVA of 38,800 for 2014 only as opposed to the sum of the LRAMVA threshold of 388,471.

4-Staff-43

Ref: Tab 3 of 2018 LRAMVA Work Form (May 1, 2017)

In Table 5, it appears that the number of months in period 1 (row 18) have not been entered correctly. In order to convert rates to a January to December year equivalent, the number of months should capture the amount of time from January to the start of the LDC's rate year. Please note that if rates were implemented in May, four months should be entered in row 18 to reflect the rate effective for the first four months of the year.

Please adjust the entries in row 18 of Table 5.

Response:

This error has been corrected in the 2018 LRAMVA model filed on conjunction with these responses.

4-Staff-44

Ref: Tab 7 of 2018 LRAMVA Work Form (May 1, 2017); Exhibit 4 of Application page 65 of 69

As part of the LRAMVA disposition, Cooperative Hydro Embrun indicated that it would collect carrying charges up to April 30, 2015. In Tab 7 of the work form, it appears that carrying charges are collected up to the period of December 30, 2015.

(a) Please confirm the time period Cooperative Hydro Embrun is collecting carrying charges until.
(b) Please confirm the amount of the carrying charges to be included in the disposition.
(c) Please re-submit a revised version of the work form to address changes to the work form in response to questions 4-Staff-40 to 4-Staff-43 above.

Response:

a) The model calculates carrying charges until December 2016.
b) 84.83 as per calculated in the 2018 LRAMVA model.
c) A revised model has been filed in conjunction with these responses.

4.0-VECC-24

Reference:

a) Embrun's Appendix 2-JC appears to be filed in a non-standard format. The format seen by VECC in other similar applications is shown below:

Programs Under Appendix 2-JC
Reporting Basis
Operations
Meter Operations
System Control Operations
Overhead\Underground Operations
Operations Supervisory
Station Operations
Sub-Total
Maintenance
Meter Maintenance
Maintenance Supervisory
Overhead\Underground Maintenance
Station Maintenance
Transformer Maintenance
Tree Trimming
Sub-Total
Community Relations
LEAP
Community Relations
Sub-Total
Customer Service
Bad Debt
Customer Billing
Customer Collection
Sub-Total
Administration
Insurance
Office Supplies
General Building
Safety Training
Regulatory Affairs
Audit, Legal & Consulting
Administrative and Human Resource
Sub-Total
Miscellaneous
Total

Is the format provided by Embrun's Appendix 2-JC (see Excel Chapter 2 Appendices) the greatest detail available for the Utility's OM&A programs? If not please provide the greater detail as shown in the sample table above.

Response:

As explained in Exhibit 4, CHEI uses OM&A programs is for regulatory reporting only. The utility prefers to use the traditional USoA accounting for purposes of planning and budgeting.

That said, in putting together this specific section of its application, CHEI started with the list above (originally introduced by Oakville Hydro in their 2014 CoS and then adopted by various other utilities). CHEI then trimmed the list down to a list of programs it felt it could commit to going forward. Although CHEI's resulting list is simple in comparison to the above list, the utility considers it maintainable and a good starting point for introducing OM&A programs. CHEI hopes to possibly expand and elaborate on its programs in future years.

4.0-VECC-25

Reference: Exhibit 4, pg. 15

a) Please describe the steps and customer charges (i.e. policies) Embrun has for customers who do not pay their bill by the due date (for example, how many days after the bill is sent does a late payment charge apply, how many days past when a disconnection notice is sent, charge for notice – if any, etc.
b) How many disconnection notices did Embrun send out in 2016?
c) Please provide the actual bad costs to date for 2017
d) Please explain how the bad debt forecast of $10,000 for 2018 was estimated.

Response:

a) Late payment charges are applied beginning the day after the due date. Seven days after the due date, a reminder notice is sent. Ten days after the reminder is sent, a disconnection notice is delivered to the door. CHEI applies a charge of $22.60 (taxes included) with a disconnection notice.

b) In 2016, 548 disconnection notices were issued. (30% are repeat customers)

c) The 2017 actual bad debt to date is $5,000.

CHEI has forecast an increase in bad debt resulting from new legislation in place preventing disconnection in winter, and the release of the OEB Decision and Order EB-2017-0101. As the decision was issued on February 23, 2017, CHEI did not have a full winter season of history on which to base its 2018 budget. Increasing the budget to $10,000 from past actual expense of approximately $5,000 was considered to be a prudent approach to allow CHEI to manage under these new operating conditions.

4.0-VECC-26

Reference: Exhibit 2/DSP/pg. 6 & Exhibit 4, page 27 & Table 19, pg. 40

a) Please provide the names of any firms other than Sproule Powerline Construction Ltd. (SPL) that carry out Embrun's operation and maintenance work?
b) Please provide the annual amount paid to SPL in 2014 forecast to be paid in 2017 and 2018 (forecast).
c) The amounts paid to SPL for operation and maintenance do not appear to match those amounts shown in the summary OM&A tables. For example, in 2016 the amount paid to SPL is $433,829. However the amounts shown for 2016 in Table 13 (pg. 19) for Operations ($22,179) and Maintenance ($43,622) are significantly less. Please explain why.
d) Furthermore, in 2016 the amount paid to SPL added to amount paid in the same year for employee compensation (see Table 16, pg.34) exceeds the total of OM&A for 2016 as shown in Table 13 -(i.e. $433,829 + $260,768 is > $601,025). Please explain this apparent discrepancy.

Response:

a) Sproule Powerline is the only contractor for the maintenance and operation of the distribution of CHE.
b)

 2014: $1,001,089 (offset by 905K in capital contribution)
 2017 Forecasted $194,500
 2018 Forecasted $213,000

c) The amount quoted by VECC includes both O&M Costs and Capitalized Costs.
d) As explained in CHEI's response to c) The amount quoted by VECC includes both O&A Costs and Capitalized Costs therefore comparing the total of O&M and Capital Costs to the Total OM&A is incorrect.

4.0-VECC-27

Reference: Exhibit 4, page 45.

a) Please provide the legal costs to-date for this application.
b) In addition to the amortized cost of $32,800 for this application Embrun has included $33,000 of annual consultant costs for regulatory matters in each year of the term of the proposed rate plan. Please explain what these costs are for.

Response:

a) The legal costs incurred so far are in the amount of $4,450. CHEI notes that post filing assistance has not yet been invoiced and therefore are not included in this to date total.
b) CHEI has a 4-year contract with Tandem Energy Services for regulatory services assisting the utility in creating a work environment that facilitates the understanding and support of change. Services include;
   - Turnkey of IRM and Cost of Service application including response to IRs.
   - Representing the utility in settlement conference, oral hearings.
   - Financial analysis reporting (Tracking of Benchmarking, ROE, projected income, budget review).
   - Update to Conditions of service.
   - RRR Annual filing and responding to follow-up questions.
   - Assistance in responding to OEB audits.
   - Creation of utility specific models to facilitate RRR reporting or Financial Reporting.
   - Creation and maintenance of Business Plan.
   - Quarterly update to the Board of Director.
   - Developing regulatory material for website.

4.0-VECC-28

Reference: Exhibit 4, page 48

a) In any of the years 2014 through 2017 has Embrun's LEAP partner had more requests for assistance that funds available. If yes please provide the number of unfulfilled requests in each year.

As per LEAP partner report:

Year	Unfulfilled Request
2014	1
2015	0
2016	0
2017	Report not available

4.0-VECC-29

Reference: Exhibit 4, page

a) Please confirm that Embrun sought a deferment of the adoption of IFRS accounting standards in its last application EB-2013-0122.
b) Please confirm that Embrun adopted IFRS accounting standards as of January 1, 2015.
c) Please provide the BDO analysis that was completed for the $21,571 Embrun is now seeking to recover.

Response:

a) Confirmed
b) Confirmed
c) Details of the analysis were presented at page 11 of Exhibit 9. CHEI offers this additional information with respect to the work performed by BDO regarding the transition of the IFRS.

- BDO discussed with management and reviewed all applicable IFRS standards in order to evaluate the impact they could potentially have on the financial statements.
- BDO analyzed the tangible capital assets and amortization policy with management in order to evaluate the impact of IAS 16. Changes were then discussed with management.
- BDO completed a conversion checklist to ensure all mandatory exemptions applicable were taken and properly applied. BDO also ensured that all optional exemptions taken by the Coopérative were properly applied. This checklist also ensured that the audit conclusion obtained on the opening balances and comparative period financial statements were not modified due to the transition.
- Preparation of financial statements as per IFRS. This required BDO to document, program and review all additional disclosures required in the financial statements of the Coopérative.
- BDO completed a disclosure checklist of more than 2,500 questions to ensure that the financial statements were in accordance with IFRS.

For propriety reason, both checklists were not provided in BDO’s response.

4.0-VECC-30

Reference: Exhibit 4, page 58

a) Please provide the actuals PILS paid in each of 2014 through 2016.

Response

a) 2014- $12,873
b) 2015- $23,044
c) 2016- $13,540

4.0 -VECC -31

Reference: Exhibit 4, LRAMVA Work Form
EB-2013-0122 DRO – Load Forecast File

a) Please confirm that the CDM adjustment included in the approved load forecast for 2014 Rates (EB-2013-0122) was 58,321 kWh which was based on 50% of 2014 expected CDM savings of 38,880.76 kWh plus 100% of 2013 expected CDM savings of 38,880.76 kWh. If not, what were the values included?
b) Please confirm that these savings were allocated to the customer classes as follows: i) Residential – 69.45%, ii) GS<50 – 15.75%, iii) GS>50 – 13.32%, Iv) Streetlighting – 1.19% and v) USL – 0.28%. If not, what was the class allocation?
c) Since the LRAMVA is based on 100% savings in all years, please explain why the total CDM adjustment used to calculate the forecast lost revenue in 2014 and 2015 should not be 77,661.52 kWh in each year (i.e., 100% of 2014 and 2015 expected savings) versus the 38,800 kWh and 0 kWh values for 2014 and 2015 respectively used by Embrun (per LRAMVA Work Form, Tab 2).
d) Please explain why Embrun assumes there were 38,800 kWh of CDM adjustment embedded in the load forecast used to set 2013 rates (per LRAMVA Work Form, Tab 2)

Response:

a) b) d) The issues raised in this specific interrogatory have been rectified in the 2018 LRAMVA model filed in conjunction with these responses. CHEI notes that it had inadvertently used the LRAMVA of 38,800 for 2014 only as opposed to the sum of the LRAMVA threshold of 388,471.

b) CHEI confirms that used a per class allocation based on kWh allocation. CHEI proposes to use the program allocation from the LRAMVA model instead.

4.0 -VECC -32-

Reference: Exhibit 4, LRAMVA Work Form
Exhibit 4,

a) Please provide a copy of the IESO's Report regarding Embrun's Verified 2011-2014 savings (in Excel format). Please also provide any reports from the IESO regarding the persistence of these savings through to 2015.

Response:

a) The Verified 2011-2014 savings (in Excel format) is filed along with these responses.

Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-45

Ref 1: Exhibit 5/Section 5.5.4/Page 11 – Long-Term Debt
Ref 2: Exhibit 5/Appendix B/Page 1 – Promissory Note

Section 1.2 of the Promissory Note attached as Appendix B indicates a 5-year term for the $1,000,000 Promissory Note. Section 1.3 indicates an amortization period of 20 years.

Please confirm if the 2.9% interest rate is for the 20 year term or is it renegotiable after 5 years.

Response:
Confirmed. The 2.9% interest rate is for the 20-year term.

5.0-VECC-33

Reference: E5. 63

a) Please explain the difference between the $1 million noted as the long-term debt and the $1,680,757 noted in the agreement with the Desjardins as being the maximum lending capacity under the agreement.
b) Why is the $680,757.48 listed as a down payment (Mise de fonds) in the agreement?
c) After the expiry of the 5 year term does the loan contain a formula for calculating a renewal interest rate?

Response:

(a) CHEI determined that it would be more cost effective to finance a portion of the project using available funds. The amount of $680,757 was used for this purpose.
(b) Please see the response to part a), above.
(c) The loan contains no formula for renewal of the loan in 5 years.

5.0-VECC-34

Reference: E5 & EA/Appendix A Financial Statements (PDF pg. 124)

a) According to Embrun's 2016 financial statements the Utility has a term deposit of $1 million maturing July 7, 2017 of this year. Was this asset reinvested and if so at what interest rate and with what institution?
b) Was the $1 million loan contingent in any fashion on renewal of the How was the term deposit.

Response:

(a) The term deposit was deposited to the account. Part of the sum will be used to finance the project. It is estimated that $300,000 to $500,000 will remain as cash flow for emergencies with Desjardins.
(b) The loan has not contingent on the remaining cash flow.

Exhibit 6 – Calculation of Revenue Deficiency

6-Staff-46

Ref: Exhibit 6/Section 6.2.1/Page 4/Table 1 – Distribution Revenues as Current Rates – 2018 Volumes

2017 Rates at 2018 Load								
	Test Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$21.8700	2,100	$21.8700	2,100	$551,124.00	$155,637.67	$706,761.67	77.98%
General Service < 50 kW	$17.9000	172	$17.9000	172	$36,969.84	$74,644.73	$111,614.58	33.12%
General Service > 50 to 4999 kW	$199.4500	9	$199.4500	9	$21,540.60	$47,068.45	$68,609.05	31.40%
Unmetered Scattered Load	$21.1600	17	$21.1600	17	$4,415.87	$451.70	$4,867.57	90.72%
Street Lighting	$1.9900	530	$1.9900	530	$12,646.72	$4,878.84	$17,525.56	72.16%
Total Fixed Revenue		2,828		2,828	$626,697.03	$282,681.40	$909,378.43	

A portion of Table 1 is replicated above. OEB staff notes that the “Fixed Charge Revenue” column duplicates the fixed rates in column 1, which is incorrect. Please provide an updated table with the fixed charge revenues calculated.

Response:

Please see table below

2017 Rates at 2018 Load								
	Test Year Projected Revenue from Existing Variable Charges							
Customer Class Name	Variable Distribution Rate	per	Test Year Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Ne Varia Reve
Residential	$0.0072	kWh	21,616,344	$155,637.67			$0.00	$155,6
General Service < 50 kW	$0.0148	kWh	5,043,563	$74,644.73			$0.00	$74,64
ral Service > 50 to 4999 kW	$3.6957	kW	12,736	$47,068.45	0.00		$0.00	$47,00
Unmetered Scattered Load	$0.0055	kWh	82,127	$451.70			$0.00	$451
Street Lighting	$8.0867	kW	603	$4,878.84			$0.00	$4,87
Total Variable Revenue			26,755,373	$282,681.40	0	0	$0.00	$282,6
2017 Rates at 2018 Load								
	Test Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% T Reve
Residential	$21.8700	2,100	$551,124.00	$155,637.67	$706,761.67	77.98%	22.02%	77.7
General Service < 50 kW	$17.9000	172	$36,969.84	$74,644.73	$111,614.58	33.12%	66.88%	12.2
ral Service > 50 to 4999 kW	$199.4500	9	$21,540.60	$47,068.45	$68,609.05	31.40%	68.60%	7.54
Unmetered Scattered Load	$21.1600	17	$4,415.87	$451.70	$4,867.57	90.72%	9.28%	0.54
Street Lighting	$1.9900	530	$12,646.72	$4,878.84	$17,525.56	72.16%	27.84%	1.93
Total Fixed Revenue		2,828	$626,697.03	$282,681.40	$909,378.43			

6-Staff-47

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

Also upon completing all interrogatories from OEB staff and intervenors please provide any updates to the following Microsoft Excel documents in working format: PILS, any Appendix 2 changes (e.g. cost allocation, rate design, and so on as required), EDDVAR spreadsheet, Tariff and Bill Impact Model and the updated cost allocation model reflecting the revised revenue requirement in the updated RRWF.

In its application, Cooperative Hydro Embrun notes that at the time of filing, the OEB had not yet updated its Bill Impact Work Form and therefore used its own bill impacts which replicate an older format of the OEB's calculation. Along with these interrogatories, OEB staff has attached an updated Tariff and Bill Impact Model to be used by Cooperative Hydro Embrun in its interrogatory responses.

Response:

Both models are being filed along with these responses.

Exhibit 7 – Cost Allocation

7-Staff-48

Ref 1: Exhibit 7/Section 7.2.1/Page 11/Table 6 – Sheet I6-1 of the Cost Allocation Model
Ref 2: Cost Allocation Model – Tab I6.1: Revenue

OEB staff notes that the data entered in Table 6 of the application does not match Tab I6.1 of the Cost Allocation Model. OEB staff notes that the data entered in the Cost Allocation Model matches to the proposed load forecast and RRWF. Please confirm that the data entered in the table on page 11 of exhibit 7 are typographical errors.

Response:

Confirmed. The table on page 11 was not updated to reflect the model.

7-Staff-49

Ref 1: Exhibit 7/Section 7.4.1/Page 19/Table 15 – 2018 Allocation
Ref 2: Exhibit 7/Section 7.4.1/Page 20
Ref 3: Revenue Requirement Work Form, Tab 11 – Cost Allocation

Reference 1 is reproduced below:

Table 15 – 2018 Allocation

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Target Range Floor	Target Range Ceiling
Residential	1.02	0.99	0.03	0.85	1.15
General Service < 50 kW	0.54	0.90	-0.36	0.80	1.20
General Service > 50 to 4999 kW	1.88	1.50	0.38	0.80	1.20
Unmetered Scattered Load	1.31	1.20	0.11	0.80	1.20
Street Lighting	0.79	0.80	-0.01	0.80	1.15

At Reference 2, Cooperative Hydro Embrun notes "At its current rates, the General Service >50kW is slightly over-recovering revenues in comparison to its allocated costs. Since the calculated ratio of 1.88 is higher than the ceiling of 1.50, adjusting it down to the ceiling is being proposed."

A portion of reference 3 is reproduced below:

Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
	Test Year	Price Cap IR Period		
	2017	2018	2019	
Residential	99.24%	99.24%	99.24%	85 - 115
General Service < 50 kW	89.93%	89.93%	89.93%	85 - 115
General Service > 50 to 4999 kW	150.06%	150.06%	150.06%	80 - 120
Unmetered Scattered Load	120.05%	120.05%	120.05%	80 - 120
Street Lighting	79.74%	79.74%	79.74%	80 - 120

(a) Please correct the RRWF at Tab 11 (reference 3) which currently notes 2017 as the test year as opposed to 2018.

(b) At reference 2, Cooperative Hydro Embrun indicates the ceiling for the GS 50 to 4,999kW rate class to be 150%. As seen in reference 3, the OEB's policy range for this rate class is 120%. Please reconcile.

(c) Please explain why Cooperative Hydro Embrun has not proposed to bring this ratio down to 120%. If any changes are required to the models, please make the updates in accordance with 6-Staff-47.

(d) Please explain how the proposed revenue to cost ratios impact the bill impacts as found in exhibit 8. For example, OEB staff notes that the revenue to cost ratio for the GS<50kW class is increasing by approximately 30%, yet the bill impact shows an overall decrease. Similarly, the revenue to cost ratio for the Residential class is decreasing, however the bill impacts show a large increase.

Response:

(a) The Test Year has been corrected in the version filed along with these responses.

(b) The ceiling at reference above (7.4.1 page 20) should have indicated "1.20%" as a ceiling.

(c) The results of the Cost Allocation indicated a Revenue to Cost ratio of 1.74%. A 0.54% downwards adjustment in a single year is generally considered to be an extreme adjustment. In the interest of rate mitigation and concern for its General Service <50 class, CHEI found it more prudent to adjust it over 2 years instead.

(d) CHEI notes that contrary to Board Staff's statement, the Revenue to Cost ratio for the GS<50 has not increased by 30%. It had decreased by 30% causing a decrease in bill impacts. The same argument goes for the Residential class whose Revenue to Cost ratio has increased by 0.05%. This, along with the migration to 100% fixed charge, increase in RTSR rates and disposition of DVAs has caused the bill impact to increase.

7-Staff-50

Asset Functionalization and Demand Allocators
Ref: Cost Allocation Model, Sheet I4 BO Assets
Ref: Cost Allocation Model, Sheet I6.2 Customer Data, Sheet I8 Demand Data

Cooperative Hydro Embrun has not separately identified primary and secondary assets for accounts 1830 – Poles towers and Fixtures, 1835 – Overhead Conductors and Devices, and 1845 – Underground Conductors and Devices. The prepared model functionalizes all assets as Secondary voltage. This can result in an unfair allocation of costs to street lighting as well as to rate classes where some customers do not receive secondary distribution, if any.

In addition, Cooperative Hydro Embrun has identified every customer in every rate class, as well as every kW of demand in every rate class as being served at secondary voltage.

(a) Please review the assets, and perform a breakout to Primary and Secondary using the best information available.
(b) Please confirm that every customer of Cooperative Hydro Embrun is connected to secondary distribution service.

Response:

(a) CHEI has reviewed the breakout of Primary and Secondary Assets and is satisfied that the information is accurate. Therefore, CHEI is not suggesting any changes from the version that was filed on May 1, 2017.
(b) CHEI confirms that every customer is connected to the secondary distribution service.

7-Staff-51

Asset Functionalization
Ref: Cost Allocation Model, Sheet I4 BO Assets

Account 1855 – Services has a negative asset value, net of Accumulated Depreciation and Contributed Capital.

Please review the gross asset, accumulated amortization, contributed capital, and amortization of contributed capital for all asset categories, and update as required.

Response:

CHEI has adjusted the accumulated depreciation allocated to account 1855 in the model filed along with these response to IRs. CHEI notes that the change had no effect on the resulting revenue-to-cost ratios.

7-Staff-52

Weighting Factors
Ref: Cost Allocation Model, Sheet I5.2 BO Assets

Cooperative Hydro Embrun has used the same weighting factor for Billing and Collecting for all rate classes.

Please provide a derivation of the Billing and Collecting weighting factors.

Response:

No derivation or calculation was needed. CHEI bills and collects all classes in the same manner. There is no difference in the time or workload required to bill an invoice regardless of the class. CHEI maintains that its Weighting factor of 1.0 for each class is accurate.

7-Staff-53

Customer Data
Ref: Cost Allocation Model, Sheet I6.2 Customer Data

The Street Light rate class does not have the Number of Devices field populated at cell J18. As a result, the Street Lighting Adjustment Factors calculation at the bottom of this sheet is unable to calculate an adjustment factor, and it is not possible for the model to accurately allocate costs to the Street Light rate class.

Please review the device count and connection count, and update as necessary.

Response:

CHEI notes that none of its Streetlights contain a daisy-chain configuration. Therefore, each device is equal to one connection.

7-Staff-54

Meter Count
Ref: Cost Allocation Model, Sheet I6.2 Customer Data, Sheet I7.1 Meter Capital

Cooperative Hydro Embrun has identified 172 GS < 50 customers on sheet I6.2 Customer Data, but has only entered a total of 163 meters on sheet I7.1 Meter Capital. Please reconcile.

Response:
The count of 172 at sheet I6.2 represented the number of meters at the end of 2016. CHEI has updated the model filed with these IRs shows a revised customer count of 172 in sheet I7.1.

7-Staff-55

Meter Reading

Ref: Cost Allocation Model, Sheet I6.2 Customer Data, Sheet I7.2 Meter Reading

Cooperative Hydro Embrun has identified 172 GS < 50 customers and 9 GS > 50 customers on sheet I6.2 Customer Data, but has not entered any meter reading for GS < 50, and only entered 8 interval meter reading for GS > 50. Please reconcile.

Response:

CHEI has updated the model filed with these IRs shows a revised customer count of 9 in sheet I7.2.

7-Staff-56

Demand Allocators
Ref: Cost Allocation Model, Sheet I6.1 Revenue, Sheet I8 Demand Data

Cooperative Hydro Embrun has used a forecast of 603 kW of streetlight billing demand on sheet I6.1 Revenue, and a on Sheet I8 Demand Data, a 12 NCP Demand of 1,092 kW for the same rate class. The billing demand value on sheet I6.1 Revenue should match or exceed the 12 NCP value on sheet I8 Demand Data. This may be related to IR 3-Staff-25.

Please review the calculation of the values on sheet I8 Demand Data, and correct as necessary.

Response:

CHEI respectfully disagrees with Board Staff and maintains that the Forecasted kW should match the results of the Load Forecast as opposed to the Demand for 12 NCP.

7-Staff-57

Load Profile Update
Ref: Update of Demand Data worksheet

Cooperative Hydro Embrun has used load profiles, prepared by Hydro One based on 2004 data as the starting point for its 2018 load profiles and demand allocators.

Please confirm that Cooperative Hydro Embrun will endeavour produce updated load profiles based on smart meter and interval meter data in its next rebasing application.

Response:

CHEI is unable to commit to producing updated load profiles. CHEI notes that such an update will require concise details/instructions on how original study conducted by Hydro One in 2004-2005 was determined, as well as a common methodology to incorporate smart meter data.

7-Staff-58

Load Profile Update
Ref: Update of Demand Data worksheet

In calculating the 1NCP values for each rate class, Cooperative Hydro Embrun has selected the peak for January, rather than selecting the class peak for each rate class.

Please revise the 1NCP calculation to reflect the class peak for each rate class.

Response:

The utility has updated its Demand Data using the best practices available at this time and only commits to update the Demand Data in relation to its proposed test year load forecast.

7.0 – VECC –35

Reference: Exhibit 7, page 16
Cost Allocation Excel Model, Tab O1

a) In Tables10 and 12 the amounts by customer class shown under "Existing Rates" do not align with the Cost Allocation model results. Please reconcile.

Response:

The information at Table 10 is not intended to show the same information as Tab O1. Its intent is to show the per class allocation of the proposed revenue requirement using the per class allocation from existing rates.

2017 Rates at 2018 Load

	Test Year Projected Revenue from Existing Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$21.8700	2,100	$551,124.00	$155,637.67	$706,761.67	77.98%	22.02%	77.72%
General Service < 50 kW	$17.9000	172	$36,969.84	$74,644.73	$111,614.58	33.12%	66.88%	12.27%
General Service > 50 to 4999 kW	$199.4500	9	$21,540.60	$47,068.45	$68,609.05	31.40%	68.60%	7.54%
Unmetered Scattered Load	$21.1600	17	$4,415.87	$451.70	$4,867.57	90.72%	9.28%	0.54%
Street Lighting	$1.9900	530	$12,646.72	$4,878.84	$17,525.56	72.16%	27.84%	1.93%
Total Fixed Revenue		2,828	$626,697.03	$282,681.40	$909,378.43			

7.0 – VECC –36

Reference: Exhibit 7, pages 17 - 20
Cost Allocation Excel Model, Tab O1
RRWF, Tab 11 (Cost Allocation)

a) The Status Quo Ratios in Table 13 don't match those in Table 14. Please reconcile.
b) In Table 14, part D, please confirm that the first column of Proposed Ratios is for 2018 (and not 2017).
c) In Table 14 part D there is no indication which customer classes' revenue to cost ratios will be increased in the second year in order to offset the revenue shortfall from moving the ratio for GS>50 from 150% to 120%. Please indicate which classes' ratios will be adjusted in order to maintain revenue neutrality.
d) The Calculated R/C Ratios in Table 15 don't match those from the Cost Allocation model. Please reconcile.
e) With respect to the discussion on page 20 regarding the proposed changes in the ratios the starting points referred to do not match the Status Quo ratios for the various classes. Please provide an explanation of the change proposed for each class relative to its status quo value. In responding, please specifically address the following:
   i. Why the Residential ratio is being increased from 94% to 99% when the Streetlight ratio is only being increased to 80%. (per RRWF, Tab 11)
   ii. Why is the GS<50 ratio is being decreased from 119% to 90% (per RRWF, Tab 11).

Response:

(a) This was a simple error in transposing. The corrected table is shown below. (based on information filed in the May 1 application)

C) Rebalancing Revenue-to-Cost (R/C) Ratios					
Class		**Previously Approved Ratios**	**Status Quo Ratios**	**Proposed Ratios**	**Policy Range**
		Most Recent Year:	**(7C + 7E) / (7A)**	**(7D + 7E) / (7A)**	
		2014			
		%	**%**	**%**	**%**
Residential		107.00	94.44	99.24	85 - 115
General Service < 50 kW		88.00	119.23	89.93	80 - 120
General Service > 50 to 4999 kW		103.00	174.31	150.06	80 - 120
Unmetered Scattered Load		70.00	121.71	120.05	80 - 120
Street Lighting		70.00	73.64	79.74	85 - 115

(b) CHEI confirms that the information should have stated 2017. The 2018 Models were not available at the time of the filing.

(c) During year 2 of the adjustment, CHEI intends on applying the shortfall to classes that fall below 1.0. Under this scenario, adjustments would be made to the Streetlight class and the GS<50 class. The final adjustment will be made post decision.

(d) This was a simple error in transposing. The corrected table is shown below. (based on information filed in the May 1 application)

Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Variance**
Residential	0.94	0.99	-0.05
General Service < 50 kW	1.19	0.90	0.29
General Service > 50 to 4999 kW	1.74	1.50	0.24
Unmetered Scattered Load	1.22	1.20	0.02
Street Lighting	0.74	0.80	-0.06

(e) CHEI provided an overall justification of its proposed ratio in Exhibit 7.

i. Both the Residential and Streetlights were adjusted by an equal 0.6 points. This was done in an effort to mitigate rates fairly for both classes. CHEI is also mindful that because of the LED conversion, the Streetlighting class has much less load to absorb its costs and that this situation can result in large bill impacts.

ii. For the GS<50, the intent was to bring it down as much as possible without going below the 1.00 mark as is policy. The choice to move below was for rate mitigation purposes however, with the proposed changes as a result of these interrogatories, or settlement, this may or may no longer be the case. The proposed revised ratios are shown below. (based on information filed in conjunction with these responses)

					Bill Impacts		**Shortfall Reconciliation**
Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Variance**				
Residential	0.9600	0.9700	-0.0100		5.62%		-9,257.3
General Service < 50 kW	1.1800	1.1800	0.0000		3.11%		0.0
General Service > 50 to 4999 kW	1.3900	1.2000	0.1900		-2.01%		11,290.8
Unmetered Scattered Load	1.2300	1.2000	0.0300		6.18%		148.5
Street Lighting	0.7900	0.9000	-0.1100		7.76%		-3,046.9
							-865

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Exhibit 8 – Rate Design

8-Staff-59

Ref 1: Exhibit 8/Section 8.1.4/Page 12 – Retail Transmission Service Rates
Ref 2: RTSR Workform, Tab 5 – UTRs and Sub-Transmission

Please update the RTSR Workform for the most recent Hydro One Sub-Transmission rates issued by the OEB in its Decision on December 21, 2016 effective January 1, 2017 (EB-2016-0081).

The rates are:

- Retail Transmission Rate – Network Service Rate: $3.1942/kW
- Retail Transmission Rate – Line Connection Service Rate: $0.7710/kW
- Retail Transmission Rate – Transformation Connection: $1.7493/kW

Response:

CHEI has updated its model with the 2018 version which contains the above rates.

8-Staff-60

Ref: Exhibit 8/Section 8.1.10/Page 24/Table 15 – Calculation of Proposed Low Voltage Charges

Please explain the significant difference in the uplifted versus non uplifted volumes for the Street Lighting rate class, and make any corrections, as required.

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues

Customer Class Name		RTSR Rate	Uplifted Volumes	Revenue	% Alloc
Residential	kWh	$0.0059	22,548,045	$132,492	70.83%
General Service < 50 kW	kWh	$0.0051	5,260,949	$26,830	14.34%
General Service > 50 to 4999 kW	kW	$2.0670	12,736	$26,326	14.07%
Unmetered Scattered Load	kWh	$0.0051	85,667	$437	0.23%
Street Lighting	kW	$1.5979	603	$964	0.52%
TOTAL			**27,908,005**	**$187,049**	**100.00%**

Customer Class Name	% Allocation	Charges	Not Uplifted Volumes	Rate	per
Residential	70.83%	69,699	21,616,344	$0.0032	kWh
General Service < 50 kW	14.34%	14,115	5,043,563	$0.0028	kWh
General Service > 50 to 4999 kW	14.07%	13,849	2,827,501	$0.0049	kW
Unmetered Scattered Load	0.23%	230	82,127	$0.0028	kWh
Street Lighting	0.52%	507	393,969	$0.0013	kW
TOTAL	**100.00%**	**98,400**	**29,963,508**		

Response:

The rate rider calculations for the Street Lighting class incorrectly used kWh as a determinant instead of kW. The issue has since then been corrected.

8-Staff-61

Ref: Exhibit 8/Section 8.1.11/Page 25 – Loss Adjustment Factors

Cooperative Hydro Embrun notes that although it was not directed to conduct a line loss study as part of its previous cost of service application, the utility makes a point of doing so prior to each rebasing application.

Has Cooperative Hydro Embrun included the cost of the new study in this application? If so, please indicate where the costs have been included.

Response:

The costs of the study were capitalized in 2016 in the following accounts

1835 - $12,917
1845 - $12,917

CHEI included the project in Appendix 2-A under System Access

Ref: Appendix A Historical Capital Project 2013-2017
Ref: Capital Actual Expenditures 2016

8-Staff-62

Ref 1: Exhibit 8/Section 8.1.11/Page 26 – Loss Adjustment Factors
Ref 2: Chapter 2 Appendices, Tab 2-R

With respect to row A(1), the instructions on Tab 2-K note: If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

Please explain why row A(1) has not been populated.

Response:
CHEI's metering installation is on the low voltage side of the transformer at the interface between the embedded distributor and the host distributor.
CHEI maintains that it populated the table in accordance with the OEB's instructions.

A(1) *If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.*

A(2) If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. *For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.*

8-Staff-63

Ref 1: Exhibit 8/Section 8.1.16/Page 32 – Rate Mitigation/Foregone Revenue
Ref 2: Exhibit 8/Section 8.1.2/Pages 5-6 – Rate Design Policy Consulation
Ref 3: EB-2012-0410 Board Policy: A New Distribution Rate Design for Residential Electricity Customers

Cooperative Hydro Embrun indicates that the total bill impacts for customers at the 10^{th} percentile of consumption are over 10% (15.72%) and has analysed and tested all options available to the utility to minimize the rates for low volume consumers. For example, selecting a longer transition periods for the transition to fixed rate.

Currently, the disposition periods set out below have been proposed as part of the application.

Description	Disposition Period
Accounts 1550,1551,1584,1586,1595	1
Accounts 1580,1588	1
Account 1589 Global Adjustment	1
Group 2 Accounts	1
Account 1568 LRAMVA	1
Fixed Rate Design Transition	5 (2 years remaining)

(a) Please provide bill impact (total bill % and $) scenarios using illustrating 2 and 3 year disposition periods for the Group 1 and Group 2 DVAs, while keeping all else proposed in the application the same.

Response:
CHEI is unable to provide a response to this interrogatory in the time provided. However, CHEI notes that the disposition for Group 1 (1550, 1551, 1584, 1586, 1595) of $163,798 and CHEI notes that the disposition for Group 1 (1580 and 1588) of -$161,425 nearly offset each other.

For the remainder of the total disposition of $32,521(1508 of $21,571 and 1568 of $10,950), CHEI is amenable to a longer disposition if it helps mitigate rates.

8.0 –VECC - 37

Reference: Exhibit 8, pages 5 and

a) On page 5 Embrun indicates that it is proposing to implement the Board's fixed rate policy for Residential customers over a total of 4 years, with 2 years remaining. However, at page 15, Table 19 indicates a 5 year transition period. Please reconcile.

Response:

(a) CHEI confirms that the proposed adjustment is year 3 of a total of 4 years (2016-2019). 2019 should be the final adjustment required to achieve a 100% fixed rate.

8.0 –VECC - 38

Reference: Exhibit 8, page 24
Exhibit 8, Appendix B (Proposed Tariffs)

a) With respect to Table 15, the LV rates for GS>50 and Steetlighting appear to have been calculated by dividing the allocated LV costs by each class' forecast kWh. However, the rates are expressed on a per kW basis in the proposed tariff sheets. Please review and reconcile.

Response:

(a) Please see response to 8-Staff-60.

8.0 –VECC - 39

Reference: Exhibit 8, pages 25-26
Chapter 2 Appendices, Appendix 2-R (Loss Factors)

a) On page 25 Embrun makes reference to being embedded in HONI and using a SFLF of 1.0034 which it does in Table 16 when calculating its proposed loss factor. However, Appendix 2-R indicates that the SFLF for distributors embedded in HONI is 1.034. Please review and reconcile.

Response:

(a) CHEI confirms that the supply facility loss factor (SFLF) should have cited as 1.0034. CHEI confirms that the proposed LF factor for 2018 was based on the correct SFLF 1.0034.

8.0 –VECC - 40

Reference: DVA Continuity Schedule (Excel Model)., Tab 12 (Rate Rider Calculations)
Exhibit 8, Appendix B (Proposed Tariff)
Exhibit 8, Appendix C (Bill Impacts)

a) Please provide a schedule that, for the Residential class, reconciles the rate rider calculation results as set out in the DVA Continuity Schedule with the Rate Riders set out in the Proposed Tariffs and Bill Impacts appendices.

Response: CHEI confirms that the DVA rate riders used in the application were incorrect. As requested in 6-Staff-47, CHEI has populated the 2018 Bill Impact WorkForm which reconciles with the DVA Continuity Schedules and its rate riders.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-64

Ref: Deferral and Variance Account Work Form, July 14, 2017

On July, 24, 2017, the OEB posted an updated Deferral and Variance Account Work Form which corrected for some inconsistencies in the previous version.

To ensure that account balances are allocated appropriately to all rate classes, please populate and file the latest version of the Deferral and Variance Account Work Form.

Response:

Deferral and Variance Account Work Form was updated. Refer to attached document.

9-Staff-65

Ref: EDDVAR Continuity Schedule and 2.1.7 Reporting for 2016, Account 1592

According to Cooperative Hydro Embrun's 2.1.7 reporting as of December 31, 2016, there is a balance of $13,097 in Account 1592, PILs and Tax Variances. However, there is no balance shown in Cooperative Hydro Embrun's Continuity Schedule.

(a) Please explain the discrepancy between the evidence filed and the 2.1.7 reporting.
(b) Why is Cooperative Hydro Embrun not proposing disposition of the balance in this account?
(c) Please update the evidence as necessary.

Response:

(a) Balance in Account 1592 consists of the Future income tax asset/liability recorded based on the differences between the accounting balances and fiscal balances. This amount was not originally included in the DVA Schedule.
(b) This account will be brought back to $0 when there are no longer any temporary differences between the accounting balances and fiscal balances.
(c) CHEI has updated the tab <2016 Continuity Schedule> included in the DVA Continuity Schedule (Excel).

9-Staff-66

Ref: Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications, Page 66

Effective May 23, 2017, per the OEB's letter titled Guidance on Disposition of Accounts 1588 and 1589, applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in the RSVA Power (Account 1588) and RSVA GA (Account 1589) variance accounts. In doing so, distributors are to follow the guidance provided in the above noted letter.

Please update Cooperative Hydro Embrun's EDDVAR Model to reflect any RPP settlement true-up claims.

Response:

There are no settlement true-up claims to reflect in the EDDVAR Model.

The procedures of the Cooperative Hydro Embrun was already in accordance with OEB's letter titled Guidance on Disposition of Accounts 1588 and 1589.

- RPP settlement true-up claims are conducted monthly.
- The year-end settlement true up claim was completed before the settlement claim with IESO for the final month of the first quarter of the following fiscal year.
- The balances in the variances of 1588 and 1589 accounts for the RPP settlement amounts pertains to the period that is being requested for disposition. As such, the amounts included in the variances of 1588 and 1589 represent the period of January to December for that specific year.
    - Hydro One invoices the Cooperative Hydro Embrun. Each invoice contains the current month's charge type 148 and the previous month's charge type 1142. These amounts are properly reflected in their respective months.
    - Please refer to Q68 for additional explanation on the Hydro One invoicing.
- Since there was no adjustments regarding the RPP settlement true-up claims, there is no differences between the variances of 1588 and 1589 and the audited financial statements. No adjustments were required in the DVA continuity schedule submitted.

9-Staff-67

Ref: GA Analysis Workform
Ref: Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications, Page 67

On July 24, 2017 the OEB issued its Deferral and Variance Account Workform for 2018 cost of service rate application. Given that Cooperative Hydro Embrun filed its application before this date, please update the Deferral and Variance Account Workform by completing sheet 7.a GA Analysis Workform.

Response:

Sheet 7.a GA Analysis Workform has been completed.

9-Staff-68

Ref: GA Analysis Workform

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approaches is used:
   a) Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively
   b) Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equalling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equalling GA RPP is credited into Account 1589.
   c) Another approach. Please explain this approach in detail.

2) With regards to the Dec. 31, 2016 balance in Account 1589:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are reconciling items #1a, 1b in the GA Analysis Workform or if there are any proposed adjustments to Account 1589 in the DVA Continuity Schedule for the true up impacts, please quantify the adjustments that relate to each of the following items:
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
      iii. Credit of GA RPP (Charge Type 142) if the approach under IR 1b is used

3) With regards to the Dec. 31, 2016 balance in Account 1588:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are any proposed adjustments to Account 1588 in the DVA Continuity Schedule for the impacts of RPP settlement true up, please quantify the adjustment that relate to each of the following items:
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - Commodity (Charge Type 101)
      iii. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages

iv. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type)

Response:
*** Please note that the Cooperative Hydro Embrun does not receive IESO invoice. They are invoiced by Hydro One. ***
In order to properly assess this question, we clarified the type of adjustments based on a Hydro One invoice, which was clarified by Raj Sabharwal, Project Advisor at the OEB, on October 5, 2017.

- Charge Type 1142 represents the declaration bill 100 adjustment
- Charge type 148 represents the Global adjustment

1. The following approach is used:
    a. Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively
2. Refer to answers below for each sub-questions
    a. The items that flow into the account are based on actuals at year-end.
    b. There are no reconciling items #1a or 1b in the GA Analysis Workform. In addition, there are no proposed adjustments for the true up impacts.
3. Refer to answers below for each sub-questions
    a. The items that flow into the account are based on actuals at year-end.
    b. There are no reconciling items #1a or 1b in the GA Analysis Workform. In addition, there are no proposed adjustments for the true up impacts.

9-Staff-69

Ref 1: EDDVAR Model, Tab 2 – Continuity Schedule
Ref 2: 2012 IRM Decision and Order (EB-2011-0164), Page 8

OEB staff notes that in column Q, the 2012 OEB-approved principal amounts have been transposed for Accounts 1588 - Power and 1589 – Global Adjustment.
Please make the necessary corrections to the continuity schedule.

Response:

The necessary corrections were made to the continuity schedule in order to properly record the OEB's approved disposition for 2012 in the correct accounts.

9-Staff-70

Ref: EDDVAR Model, Tab 2 – Continuity Schedule

OEB staff notes that interest amounts on the balances requested for disposition up to December 31, 2017 have not been included.

Please make the necessary corrections to the continuity schedule.

Response:

Interest amounts on the balances requested for disposition up to December 31, 2017 have been included in the continuity schedule.

9-Staff-71

Ref 1: Exhibit 1/Section 1.3.10/Page 17 – Board Directive from Previous Decisions
Ref 2: Exhibit 1/Page 43 – Overview of Deferral and Variance Account Disposition
Ref 3: Exhibit 9/Section 9.3.2//Page 11 – Disposition of DVAs Used by the Applicant

At reference 1, Cooperative Hydro Embrun notes that it is not aware of any OEB directives from any previous OEB decisions that require addressing.

OEB staff notes that in its 2016 IRM Decision (EB-2015-0063), the OEB ordered an audit of Account 1595 and noted that disposition of the account will be considered in the next rate application following the audit. Similarly, in Cooperative Hydro Embrun's 2017 IRM Decision (EB-2016-0065), the OEB noted that given that the results of the OEB's audit were not yet available, the clearance of Account 1595 was not appropriate at that time. Cooperative Hydro Embrun was expected to bring forward the request for disposition of Account 1595 in the first application following completion of the audit.

(a) If the audit has been completed, please provide a table summarizing the findings of the audit, the resulting adjustments, and an explanation of each adjustment.
(b) Please confirm that the table provided in (a) includes all of the adjustments required by the audit.
(c) If any changes are required to the application as a result of the OEB's audit, please make the necessary corrections to the DVA Continuity Schedule as part of the EDDVAR Model and update Cooperative Hydro Embrun's request for disposition of its DVAs.
(d) If changes are made in response to part (c) above, please confirm that these adjustments align with the findings of the OEB audit.

Response:

a) Audit of Account 1595 was completed. All the required adjustments are seen below.

	GL Balance as at Dec 31 2016	Double refund to Customers included in GL but excluded in DVA	Interest income that was adjusted following OEB audit	Reclassification of the stranded meters	Prior year dispositions wrongly recorded in other 1595's accounts	Reclassification to the future income tax	Balance as at Dec 31, 2016 as per rebuilt DVA	Correction of erroneous Double refund to Customers regarding account 1595 (2012)	**Revised balance of DVA**
Account 1595									
2010	2,262.23	-	41.47	-	-	-	2,303.70	-	**2,303.70**
2012	(1,092.43)	-	(847.10)	-	14,507.00	-	12,567.47	-	**12,567.47**
2014	114,588.06	(111,894.00)	(5,122.72)	(5,198.04)	3,851.96	382.00	(3,392.74)	111,894.00	**108,501.26**
	115,757.86	(111,894.00)	(5,928.35)	(5,198.04)	18,358.96	382.00	11,478.43	111,894.00	**123,372.43**

b) The table provided in (a) includes all of the adjustments required by the audit.

c) The changes required because of the OEB's audit were made to the DVA Continuity Schedule and are included in the 2018 request for disposition.

d) The changes made as part of (c) align with the findings of the OEB audit.

9-Staff-72

Ref 1: Exhibit 9/Section 9.8/Page 29 – Account 1576 Accounting Changes Under CGAAP
Ref 2: EDDVAR Model, Tab 6 – Rate Rider Calculations

Cooperative Hydro Embrun transitioned to MIFRS on January 1, 2015 and therefore the difference in depreciation due to the adoption of useful lives was addressed in its 2014 CoS application. Cooperative Hydro Embrun notes that it has not used Account 1576 in this application and is therefore requesting discontinuation of this account.

OEB staff notes that at Tab 6 of the EDDVAR Model, a balance of -$0.44 is being disposed to all rate classes and a rate rider is calculated for the GS 50 to 4,999kW rate class. Please confirm this is an error and remove the amounts for Account 1576.

Response:

Consists of a rounding error. Balance should be at $0 and was adjusted accordingly in the Continuity schedule.

9-Staff-73

Ref 1: Exhibit 9/Section 9.9.2/Pages 35-37 – Calculation of Rate Rider
Ref 2: EDDVAR Model, Tab 6 – Rate Rider Calculations

(a) OEB staff notes that the rate riders listed in the tables on the above noted pages of the application do not match those being produced from the EDDVAR Model. Please reconcile and/or update the evidence as necessary.
(b) OEB staff notes that Cooperative Hydro Embrun has calculated its Group 2 rate riders for all rate classes on a fixed basis. The OEB policy requires fixed rate riders for Group 2 for residential class only. Please recalculate update the rate riders for Group 2.
(c) OEB staff notes that the last column in the Rate Rider Calculation for Group 2 Accounts is labelled “Rate Rider for RSVA – Power – Global Adjustment”. Please confirm that this Table is related to Group 2.

Response:

a) Please see response to 8-VECC-40.
b) CHEI has updated the DVA model to reflect a fixed rate rider for the Residential Class only.
c) Account 1589 - Rate Rider for RSVA – Power – Global Adjustment is part of Group 1.