Coopérative
Hydro Embrun
Inc.

June 28, 2022

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

Regarding: 2022 Cost of Service Application (EB-2022-0022)

Please find attached a revised version of the settlement agreement with the three following corrections.

- The page numbering has been corrected
- The title of Table 5 was corrected to says “2023 Revenue Requirement Summary”
- The title of Table 17 was corrected to say “2023 Distribution Rates”

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
Coopérative Hydro Embrun
821 Notre-Dame St, Embrun, ON K0A 1W1
(613) 443-5110

EB-2022-0022

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

AND IN THE MATTER OF an application by
Cooperative Hydro Embrun Inc.
For an order approving just and reasonable rates and
Other charges for electricity distribution beginning
January 1, 2023.

Cooperative Hydro Embrun Inc.

Settlement Proposal

Filed: June 24, 2022

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A. Proposed January 1, 2023, Tariff of Rates and Charges
B. Bill Impacts
C. Revenue Requirement Work Form
D. Summary of Accounting Guidance of Accounts 1588/1589

CHEI has filed revised models as evidence to support this Settlement Proposal. The models have been filed through the OEB’s e-filing service and include:

1. Chapter 2 Appendices
2. Revenue Requirement Work Form
3. Income Tax PILs Model
4. Load Forecast Model
5. Cost Allocation Model
6. DVA Continuity Schedule
7. RTSR Model
8. Tariff Schedule and Bill Impact Model

9. Load Profile Model (HONI)
10. Benchmarking Model
11. GA Workform
12. 1595 Workform
13. Accelerated CCA calculations model

SETTLEMENT PROPOSAL

Cooperative Hydro Embrun Inc. (the Applicant or CHEI) filed a Cost-of-Service application with the Ontario Energy Board (the OEB) on February 1, 2022, under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the Act), seeking approval for changes to the rates that CHEI charges for electricity distribution, to be effective January 1, 2023 (OEB file number EB-2022-0022) (the Application).

The OEB issued a Letter of Direction and Notice of Application on February 23, 2022. In Procedural Order No. 1, dated March 22, 2022, the OEB approved the Vulnerable Energy Consumers Coalition (VECC) as an intervenor.

The Procedural Order also indicated the prescribed dates for the written interrogatories, CHEI's responses to interrogatories, a Settlement Conference, and various other elements in the proceeding.

On March 25, 2022, OEB staff, on behalf of all the parties, submitted a proposed issues list (the Issues List) to the OEB for approval. The OEB approved the Issues List on March 30, 2022.

CHEI filed its interrogatory responses with the OEB in two batches, the first on May 3, 2022, and the second on May 6, 2022.

The Settlement Conference was convened on May 16 and 17, 2022 in accordance with the OEB's Rules of Practice and Procedure (the Rules) and the OEB's Practice Direction on Settlement Conferences. VECC and OEB Staff participated in the Settlement Conference. Pursuant to the direction from the OEB on April 7, 2022, OEB Staff's participation in the Settlement Conference is as a party.

Andrew Pride acted as the facilitator for the Settlement Conference.

CHEI, VECC and OEB staff (collectively referred to below as the Parties), reached a full, comprehensive settlement regarding CHEI's 2023 Cost of Service Application. The details and specific components of the settlement are detailed in this Settlement Proposal.

This document is called a Settlement Proposal because it is a proposal by the Parties presented to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. In entering into this Settlement Proposal, the Parties understand and agree that pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that the Settlement Conference was confidential in accordance with the OEB's Practice Direction on Settlement Conferences. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the specific rules with respect to confidentiality and privilege are as set out in the Practice Direction on Settlement Conferences, as amended on February 17, 2021. The Parties have interpreted the revised Practice Direction on Settlement Conferences to mean that the documents and other information provided during the course of the Settlement Conference itself, the discussion of each issue, the offers and counteroffers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the Parties agree that attendees are deemed to include, in this context, persons who were not in attendance at the Settlement Conference but were a) any persons or entities that the Parties engaged to assist them with the Settlement Conference, and b) any persons or entities from whom the attendees' sought instructions with respect to the negotiations.

This Settlement Proposal provides a brief description of each of the settled issues, as applicable, together with references to the evidence. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to interrogatories, all other components of the record up to and including the date here of, and the additional information included by the Parties in this Settlement Proposal and the attachments and appendices to this document.

Included with the Settlement Proposal are attachments that provide further support for the proposed settlement, including responses to Pre-Settlement Clarification questions (Clarification Responses). The Parties acknowledge that the attachments were prepared by CHEI. VECC and OEB Staff have reviewed the attachments and are relying on the accuracy of the attachments and the underlying evidence in entering into this Settlement Proposal.

For ease of reference, this Settlement Proposal follows the format of the final approved Issues List, with additional sub-issues added as appropriate in order to highlight specific aspects of the settlement.

According to section 6 of the Practice Direction on Settlement Conferences, the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Any such adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the OEB does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the OEB accepts may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties must agree with any revised Settlement Proposal as it relates to that issue, or take no position, prior to its resubmission to the OEB.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not CHEI is a party to such proceeding, provided that no Party shall take a position that would result in the Settlement Proposal not applying in accordance with the terms contained herein.

Where, in this Settlement Proposal, the Parties accept the evidence of CHEI, or agree to any issue, term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words “for the purpose of settlement of the issues herein” shall be deemed to qualify that acceptance or agreement.

SUMMARY

The Parties were able to reach agreement on all aspects of the Application: capital costs, operations, maintenance & administration (OM&A) costs, revenue requirement-related issues, including the accuracy of the revenue requirement determination, OEB policies and practices and accounting.

In reaching this Settlement Proposal, the Parties have been guided by the Filing Requirements for 2023 rates and the approved Issues List.

This Settlement Proposal reflects a full settlement of the issues in the proceeding. The Parties have described below, in detail, areas where they have settled an issue by agreeing to adjustments to the Application as updated.

This Settlement Proposal will, if accepted, result in total bill decrease of -$1.53 or -1.2% per month for the typical residential customer consuming 750 kWh per month.

The overall financial impact of the Settlement Proposal is to increase the total base revenue requirement by $3,194 or 0.27% from $1,165,281 to $1,168,475.

The Parties note that this Settlement Proposal includes all tables, appendices and the Excel models that represent the evidence and the settlement between the Parties at the time of filing the Settlement Proposal, and the agreed Tariff of Rates and Charges.

A Revenue Requirement Work Form (RRWF) incorporating all terms that have been agreed to is filed with the Settlement Proposal. Through the settlement process, CHEI has agreed to certain adjustments to its original Application. The changes are described in the following sections.

CHEI has provided the following tables summarizing the Application and highlighting the changes to its Rate Base and Capital, Operating Expenses, and Revenue Requirement as between CHEI's Application as filed, the interrogatory process and this Settlement Proposal.

Table 1 – Summary of 2023 Revenue Requirement

Particular	Jan 31, 2022 (rev Feb 14,2022)	Response to IRs May 2, 2022	Variance over Original Application	Settlement Proposal June 24 2022	Variance over IRs
Long Term Debt	3.49%	3.49%	0.00%	3.49%	0.00%
Short Term Debt	1.17%	1.17%	0.00%	1.17%	0.00%
Return on Equity	8.66%	8.66%	0.00%	8.66%	0.00%
Weighted Debt Rate	3.34%	3.34%	0.00%	3.34%	0.00%
Regulated Rate of Return	**5.47%**	**5.47%**	**0.00%**	**5.47%**	**0.00%**
			$0	$0	
Controllable Expenses	$753,157	$769,895	$16,738	$769,895	$0
Power Supply Expense	$3,293,006	$3,282,755	-$10,251	$3,441,940	$159,185
Total Eligible Distribution Expenses	$4,046,164	$4,052,650	$6,487	$4,211,835	$159,185
Working Capital Allowance Rate	7.50%	7.50%	0.00%	7.50%	0.00%
Total Working Capital Allowance ("WCA")	**$303,462**	**$303,949**	**$487**	**$315,888**	**$11,939**
			$0	$0	$0
Year End Test Year Average Gross Asset	$7,185,613	$7,165,369	-$20,244	$7,045,069	-$120,300
Year End Test Year Average Acc Depr.	$2,708,489	$2,715,821	$7,332	$2,713,355	-$2,465
Average Fixed Asset	$4,477,124	$4,449,548	-$27,576	$4,331,714	-$117,835
Working Capital Allowance	$303,462	$303,949	$487	$315,888	$11,939
Rate Base	**$4,780,587**	**$4,753,497**	**-$27,089**	**$4,647,601**	**-$105,896**
			$0	$0	$0
Regulated Rate of Return	5.47%	5.47%	0.00%	5.47%	0.00%
Regulated Return on Capital	**$261,269**	**$259,788**	**-$1,480**	**$254,001**	**-$5,787**
Deemed Interest Expense	$95,669	$95,127	-$542	$93,008	-$2,119
Deemed Return on Equity	$165,600	$164,661	-$938	$160,993	-$3,668
			$0	$0	$0
OM&A	$753,157	$769,895	$16,738	$769,895	$0
Depreciation Expense	$180,507	$191,991	$11,484	$188,568	-$3,424
PILs	$19,099	$12,263	-$6,836	$2,132	-$10,131
Revenue Offset	-$48,750	-$27,641	$21,109	-$46,121	-$18,480
Revenue Requirement	**$1,165,281**	**$1,206,297**	**$41,016**	**$1,168,475**	**-$37,822**

Based on the foregoing, and the evidence and rationale provided below, the Parties accept this Settlement Proposal as appropriate and recommend its acceptance by the OEB. Table 2 below illustrates the updated bill impacts that would result from the acceptance of this Settlement Proposal.

Table 2 - Bill Impact Summary

RATE CLASSES / CATEGORIES ***(e.g.: Residential TOU, Residential Retailer)***	**Units**	**Sub-Total**						**Total**	
		A		**B**		**C**		**Total Bill**	
		$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential service – RPP	kWh	-$4.13	-11.0%	-$3.09	-6.7%	-$1.62	-2.8%	-$1.53	-1.2%
GS less than 50 kw service – RPP	kWh	-$6.49	-10.9%	-$4.12	-5.1%	-$0.65	-0.6%	-$0.56	-0.2%
GS 50 to 4,999 kw SERVICE - Non-RPP (Retailer)	kW	-$36.03	-6.9%	-$100.72	-16.4%	-$50.77	-5.0%	-$20.81	-0.4%
Unmetered scattered load service - Non-RPP (retailer)	kWh	-$3.12	-51.0%	-$2.62	-24.8%	-$1.93	-12.1%	-$1.84	-3.1%
Street lighting service - Non-RPP (other)	kW	-$339.32	-15.3%	-$405.15	-18.0%	-$382.51	-15.7%	-$399.00	-5.8%
Residential service - Non-RPP (retailer)	kWh	-$4.13	-11.0%	-$4.77	-10.3%	-$3.30	-5.7%	-$3.14	-2.3%

RRF OUTCOMES

The Parties accept that the Applicant is in compliance with the OEB's required outcomes as defined by the Renewed Regulatory Framework (RRF). Subject to the adjustments noted in this Settlement Proposal, the Parties accept that CHEI's proposed rates in the 2023 Test Year will, in all reasonably foreseeable circumstances, allow the Applicant to meet its obligations to its customers while maintaining its financial viability.

1.0 PLANNING

1.1 CAPITAL

Is the level of planned capital expenditure appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- Customer feedback and preferences
- Productivity
- Benchmarking of costs
- Reliability and service quality
- Impact on distribution rates
- Trade-offs with OM&A spending
- Government-mandated obligations
- The objectives of CHEI and its customers
- The distribution system plan
- The business plan

Full Settlement

For the purpose of settlement, the Parties agree to CHEI's proposed opening 2023 rate base and 2023 net capital additions subject to the following adjustments:

a) CHEI will remove the proposed Central Park subdivision project from its planned 2022 capital plan, including the related forecast capital contribution, due to the fact that the project is in early stages of development and the utility which will serve this development has yet to be determined (Hydro One or CHEI).

b) In the event that CHEI becomes the designated distributor for the Central Park subdivision and undertakes the project and given the magnitude of the proposed project in relation to CHEI's normal annual capital spending, CHEI will be at liberty to apply for incremental funding in relation to the project under the OEB's Incremental Capital Module, including a scenario where the project goes into service in the 2023 test year. In the event the project goes into service in the test year, CHEI will only claim incremental revenue beginning in 2024.

c) CHEI will add $36,000 to its forecast capital spending for 2023 as funding for a line loss study and related capital improvements, as described more fully under Issue 5.3.

d) The Parties note that $6,000 was re-allocated to System Renewal from System Service in order to properly reflect the nature of the underlying projects in CHEI's budget; this re-allocation does not change CHEI's proposed capital spending for 2023.

Table 3 - Fixed Asset Continuity and 2022/2023 Capital Expenditures

	Jan 31, 2022 (rev Feb 14,2022)	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24 2022**	**Variance over IRs**
Gross Assets					
2022 Gross Open Bal	$6,736,013	$6,762,510	$26,497	$6,762,510	$0
2022 Additions	**$375,225**	**$295,225**	**-$80,000**	**$156,925**	**-$138,300**
2022 Disposal/Ret	$0	$0	$0	$0	$0
2022 Gross Close Bal	$7,111,238	$7,057,735	-$53,503	$6,919,435	-$138,300
Accum. Depreciation					
2022 Open Bal	$2,439,245	$2,439,415	$170	$2,439,415	$0
2022 Additions	**$178,991**	**$180,410**	**$1,419**	**$179,657**	**-$753**
2022 Disposal/Ret	$0	$0	$0	$0	$0
2022 Close Bal	$2,618,235	$2,619,825	$1,590	$2,619,072	-$753
Net Book	$4,493,003	$4,437,910	-$55,093	$4,300,364	-$137,547
2023 Gross Open Bal	$7,111,238	$7,057,735	-$53,503	$6,919,435	-$138,300
2023 Additions	**$148,750**	**$215,268**	**$66,518**	**$251,268**	**$36,000**
2023 Disposal/Ret	$0	$0	$0	$0	$0
2023 Gross Close Bal	$7,259,988	$7,273,003	$13,015	$7,170,703	-$102,300
Accum. Depreciation					
2023 Open Bal	$2,618,235	$2,619,825	$1,590	$2,619,072	-$753
2023 Additions	**$180,507**	**$191,991**	**$11,484**	**$188,568**	**-$3,424**
2023 Disposal/Ret	$0	$0	$0	$0	$0
2023 Close Bal	$2,798,742	$2,811,816	$13,074	$2,807,639	-$4,177
Net Book	$4,461,246	$4,461,187	-$59	$4,363,063	-$98,123
Average Net Book Value	$4,477,124	$4,449,548	-$27,576	$4,331,714	-$117,835
System Access	$40,000	$40,000	$0	$40,000	$0
Capital Contribution	-$10,000	-$10,000	$0	-$10,000	$0
System Renewal	$107,050	$107,050	$0	$149,050	$42,000
System Service	$6,000	$6,000	$0	$0	-$6,000
General Plant	$5,700	$72,218	$66,518	$72,218	$0
Total Expenditures	**$148,750**	**$215,268**	**$66,518**	**$251,268**	**$36,000**

The Parties accept the evidence of CHEI that the level of planned capital expenditures and the rationale for planning and pacing choices, as adjusted in this Settlement Proposal, are appropriate to maintain system reliability, service quality objectives and the reliable and safe operation of the distribution system.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 2 – Rate Base
- EXHIBIT 2 - DSP

IR Responses

- 1-Staff-1
- 6-Staff-62 to S-Staff-73
- 6-VECC-25
- 1-Staff-91
- 2-Staff-97 to 99

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explaining, giving due consideration to?

- Customer feedback and preferences
- Productivity
- Benchmarking of costs
- Reliability and service quality
- Impact on distribution rates
- Trade-offs with capital spending
- Government-mandated obligations
- The objectives of CHEI and its customers
- The distribution system plan
- The business plan

Full Settlement

For the purpose of settlement, the Parties agree to CHEI's proposed 2023 OM&A budget of $769,895, as updated in response to interrogatories. The Parties believe that the proposed budget represents a reasonable OM&A envelope for CHEI given the following metrics:

a) the proposed OM&A budget represents an annual average increase in OM&A between CHEI's approved 2018 OM&A budget and the Test Year of 2.45%,

b) the OEB's approved inflation factor from 2018 to 2022 is an annual average amount of 2.25%.

c) CHEI has experienced and is forecasting customer growth through the Test Year at an annual average rate of 1.78%.

d) based on the foregoing CHEI's projected annual growth in OM&A per customer is only 0.46% per year between its approved 2018 OM&A per customer of $299 and its proposed 2023 OM&A per customer of $306.

e) CHEI is managing non-inflationary based increases in its proposed OM&A budget including increased Cyber Security costs and Green Button related costs, both costs being the result of incremental obligations imposed on CHEI by new, incremental OEB policies; and

f) CHEI remains in the Group 1 cohort under the OEB's benchmarking results based on the Settlement Proposal included the proposed OM&A budget.

The Parties note that, currently, CHEI does not have a formal service agreement with its primary contractor Sproule Inc. The Parties have agreed that CHEI will enter into a service agreement with Sproule Inc. to formalize the terms of their working relationship within 1 year. CHEI will file a copy of that agreement with the OEB and provide it to VECC under the EB- 2022-0022 docket number to confirm compliance with this term of the Settlement Proposal; subject to the OEB's guidelines with respect to the filing of confidential information (i.e., the Parties acknowledge, for example, that the agreement is likely to contain commercially sensitive information with respect to pricing for which confidential treatment will be sought).

CHEI reallocated mailing and postage costs in the amount of $18,366 from Administrative & General Costs to Billing and Collecting in order for the Cost Allocation mechanism to allocate costs appropriately.

Table 4 - 2023 Test Year OM&A Expenses

	Jan 31, 2022 (rev Feb 14,2022)	Response to IRs May 2, 2022	Variance over Original Application	Settlement Proposal June 24 2022	Variance over IRs
Operations	$47,439	$47,439	$0	$47,439	$0
Maintenance	$49,486	$49,486	$0	$49,486	$0
Billing and collecting	$244,306	$262,444	$18,138	$280,810	$18,366
Community Relations	$3,521	$3,521	$0	$3,521	$0
Administration & General +LEAP	$408,405	$407,005	-$1,400	$388,639	-$18,366
Total	$753,157	$769,895	$16,738	$769,895	$0

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 4 – OM&A

IR Responses

- 1-Staff-2-3-7
- 2-Staff-37
- 4-Staff-49 to 60
- VECC-16-17-18-19-20-21-22
- 1- Staff-91
- 1-Staff-93
- VECC-38
-

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

2.0 REVENUE REQUIREMENT

2.1 Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

Full Settlement

The Parties agree that the methodology used by CHEI to calculate the Revenue Requirement is appropriate.

A summary of the adjusted Revenue Requirement of $1,168,475 reflecting adjustments and settled issues is presented in Table 5 – 2023 Revenue Requirement Summary below.

Table 5 - 2023 Revenue Requirement Summary

	Jan 31, 2022 (rev Feb 14,2022)	Response to IRs May 2, 2022	Variance over Original Application	Settlement Proposal June 24 2022	Variance over IRs
OM&A Expenses	$753,157	$769,895	$16,738	$769,895	$0
Amortization/Depreciation	$180,507	$191,991	$11,484	$188,568	-$3,424
Property Taxes	$0	$0	$0	$0	$0
Capital Taxes	$0	$0	$0	$0	$0
Income Taxes (Grossed up)	$19,099	$12,263	-$6,836	$2,132	-$10,131
Other Expenses	$0	$0	$0	$0	$0
Return					
Deemed Interest Expense	$95,669	$95,127	-$542	$93,008	-$2,119
Return on Deemed Equity	$165,600	$164,661	-$938	$160,993	-$3,668
Service Revenue Requirement (before Other Revenue Offsets)	$1,214,031	$1,233,937	$19,906	$1,214,596	-$19,342
Revenue Offsets	$48,750	$27,641	-$21,109	$46,121	$18,480
Base Revenue Requirement	$1,165,281	$1,206,297	$41,016	$1,168,475	-$37,822
Gross Revenue Deficiency/Sufficiency	-$124,033	-$83,032	$41,001	-$120,840	$37,808

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 6 – Revenue Requirement

IR Responses

- 1-Staff-1

- 6-Staff-62 to S-Staff-73
- 6-VECC-25
-

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

2.1.1 Rate Base

Full Settlement

The Parties accept the evidence of CHEI that the rate base calculations have been appropriately determined in accordance with OEB policies and practices, after adjustments made necessary by the various elements of the Settlement Proposal.

Table 6 - 2023 Rate Base

Particulars	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24 2022**	**Variance over IRs**
Gross Fixed Assets (avg)	$7,185,613	$7,165,369	-$20,244	$7,045,069	-$120,300
Accumulated Depreciation (avg)	-$2,708,489	-$2,715,821	-$7,332	-$2,713,355	$2,465
Net Fixed Assets (avg)	$4,477,124	$4,449,548	-$27,576	$4,331,714	-$117,835
Allowance for Working Capital	$303,462	$303,949	$487	$315,888	$11,939
Total Rate Base	**$4,780,587**	**$4,753,497**	**-$27,089**	**$4,680,725**	**-$72,772**

Controllable Expenses	$753,157	$769,895	$16,738	$769,895	$0
Cost of Power	$3,293,006	$3,282,755	-$10,251	$3,441,940	$159,185
Working Capital Base	$4,046,164	$4,052,650	$6,487	$4,211,835	$159,185
Working Capital Rate %	7.50%	7.50%	0%	7.50%	0%
Working Capital Allowance	**$303,462**	**$303,949**	**$487**	$315,888	$11,939

As noted above, the change in rate base is the result of various factors including the reduction of the 2022 capital expenses due to the removal of the Central Park subdivision project and its and related capital contribution. Capital expenditures related to the implementation of Green Button and the commissioning of a line loss study were included in 2023. The depreciation expense and accumulated depreciation for 2022 and 2023 were updated to reflect the change in capital additions in 2022 and 2023.

Due to the increase in cost of power expenses, the working capital allowance base was adjusted. The change in power supply expense is related to the change in the load forecast, OER and RTSRs.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 2 – Rate Base
- EXHIBIT 2 - DSP

IR Responses

- 1-Staff-2
- 2-Staff-15 to 43
- 4-Staff-3 to 9
- 2-Staff-96

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

2.1.2 Taxes/PILs

Full Settlement

The Parties agree that forecast PILs has been accurately calculated, including the recognition of accelerated CCA in the Test Year.

A summary of the updated PILs calculation is presented in Table 7 below.

Table 7 - 2023 Income Taxes

	Jan 31, 2022 (rev Feb 14,2022)	Response to IRs May 2, 2022	Variance over Original Application	Settlement Proposal June 24 2022	Variance over IRs
Income Taxes (Grossed up)	$19,099	$12,263	-$6,836	$2,132	-$10,131

An updated Income Tax/PILs Model has been submitted in Live Excel format as part of this Settlement Proposal.

Evidence References

- EXHIBIT 4 OM&A
- EXHIBIT 6 – PILs and Accelerate CCA

IR Responses

- 1-Staff-2
- 2-Staff-17-18
- 6-Staff-62 to 68
- 4-VECC-21
- 6-Staff-100 to 102

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

2.1.3 Revenue Offsets

The Parties agree that the Revenues Offsets have been appropriately determined.

A summary of the updated Revenue Offsets are presented in Table 8 below.

Table 8 - 2023 Revenue Offsets

	Jan 31, 2022 (rev Feb 14,2022)	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24 2022**	**Variance over IRs**
Specific Service Charges	$7,304	$7,699	$395	-$7,699	$0
Late Payment Charges	$11,450	$11,450	$0	-$11,450	$0
Other Distribution Revenues	$21,996	$492	-$21,504	-$18,972	$18,480
Other Income and Deductions	$8,000	$8,000	$0	-$8,000	$0
Total	**$48,750**	**$27,641**	**-$21,109**	**-$46,121**	**$18,480**

Evidence References

- EXHIBIT 6 Revenue Offsets

IR Responses

- 1-Staff-2
- 2-Staff-18
- 6-Staff-71-72
- 4-VECC-25
- VECC-37

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

2.1.4 Capitalization/Cost of Capital

Full Settlement

The Parties agree to CHEI's proposed cost of capital parameters as reflected in the calculation below. The Parties note that the proposed cost of capital parameters currently reflect the OEB's deemed Long Term Debt, Short Term Debt, and Return on Equity for 2022 Cost of Service Applications as applicable and will be updated to reflect the deemed rates for 2023 Cost of Service Applications when available.

VECC and OEB Staff note that CHEI's actual capital structure, for much of its history and in the proposed test year, is 100% equity with no long-term or short-term debt. As part of this Settlement Proposal neither VECC nor OEB Staff take a position with respect to the reasonableness of CHEI's forecast actual capital structure.

Table 9 - 2023 Cost of Capital Calculation

Particulars	**Jan 31, 2022 (rev Feb 14,2022)**	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24 2022**	**Settlement Proposal June 24 2022**	**Variance over IRs**
Debt								
Long-term Debt	3.49%	$93,432	3.49%	$92,902	-$529	3.49%	$90,833	-$2,070
Short-term Debt	1.17%	$2,237	1.17%	$2,225	-$13	1.17%	$2,175	-$50
Total Debt	3.34%	$95,669	3.34%	$95,127	-$542	2.86%	$93,008	-$2,119
Equity								
Common Equity	8.66%	$165,600	8.66%	$164,661	-$938	8.66%	$160,993	-$3,668
Preferred Shares	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Total Equity	8.66%	$165,600	8.66%	$164,661	-$938	8.66%	$160,993	-$3,668
Total	**5.47%**	**$261,269**	**5.47%**	**$259,788**	**-$1,480**	**5.47%**	$254,001	-$5,787

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 5 – Cost of Capital

IR Responses

- 1-Staff-2
- 5-Staff-61
- 5-VECC-24

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

2.2 Has the revenue requirement been accurately determined based on these elements?

Full Settlement

The Parties accept the evidence of CHEI that, after adjustments made necessary by the various elements of the Settlement Proposal, the proposed Base Distribution Revenue Requirement has been determined accurately.

Table 10 - 2023 Base Revenue Requirement

	Jan 31, 2022 (rev Feb 14,2022)	Response to IRs May 2, 2022	Variance over Original Application	Settlement Proposal June 24 2022	Variance over IRs
OM&A Expenses	$753,157	$769,895	$16,738	$769,895	$0
Amortization/Depreciation	$180,507	$191,991	$11,484	$188,568	-$3,424
Property Taxes	$0	$0	$0	$0	$0
Capital Taxes	$0	$0	$0	$0	$0
Income Taxes (Grossed up)	$19,099	$12,263	-$6,836	$2,132	-$10,131
Other Expenses	$0	$0	$0	$0	$0
Return					
Deemed Interest Expense	$95,669	$95,127	-$542	$93,008	-$2,119
Return on Deemed Equity	$165,600	$164,661	-$938	$160,993	-$3,668
Service Revenue Requirement (before Other Revenue Offsets)	$1,214,031	$1,233,937	$19,906	$1,214,596	-$19,372
Revenue Offsets	$48,750	$27,641	-$21,109	$46,121	$18,480
Base Revenue Requirement	$1,165,281	$1,206,297	$41,016	$1,168,475	-$37,852
Gross Revenue Deficiency/Sufficiency	**-$124,033**	**-$83,032**	**$41,001**	**-$120,870**	**$37,838**

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 6 – Revenue Requirement

IR Responses

- 1-Staff-1
- 6-Staff-62 to S-Staff-73
- 6-VECC-25

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.0 LOAD FORECAST, COST ALLOCATION, AND RATE DESIGN

3.1 Are the proposed load and customer forecast, loss factors, and resulting billing determinants appropriate and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of Cooperative Hydro Embrun's customers?

Full Settlement

The Parties agreed that, for the purpose of settlement, the following adjustments are made to the load and customer forecast for CHEI:

a) A correction to the streetlight class load forecast calculations and a correction to the number of days per month to reflect leap years.

The resulting billing determinants are presented in Table 11 below.

Table 11 - 2023 Test Year Billing Determinants

Particulars	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24 2022**	**Variance over IRs**
Residential	20,126,172	20,150,710	24,538	20,274,072	123,362
General Service < 50 kW	4,617,010	4,620,558	3,547	4,620,092	-466
General Service > 50 to 4999 kW	3,952,566	3,960,295	7,729	3,959,895	-399
Unmetered Scattered Load	93,084	88,338	-4,746	88,338	0
Street Lighting	241,169	242,877	1,708	234,836	-8,041
	29,030,001	**29,062,778**	**32,777**	**29,177,234**	**114,456**
Residential	0	0	0	0	0
General Service < 50 kW	0	0	0	0	0
General Service > 50 to 4999 kW	11,425	11,414	-10	11,413	-1
Unmetered Scattered Load	0	0	0	0	0
Street Lighting	652	655	3	655	0
	12,077	**12,069**	**-7**	**12,068**	**-1**

Evidence References

- EXHIBIT 3 – Load and Customer Forecast

IR Responses

- 3-Staff-44-48
- 3-VECC-10-14
- VECC-34 to 36

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.1.1 Customer/Connection Forecast

Full Settlement

The Parties have agreed to the forecast of customers/connections, as updated in accordance with the adjustments set out under issue 3.1, as set out in Table 12 below.

Table 12 - Summary of 2023 Load Forecast Customer Counts/Connections

Particulars	Jan 31, 2022 (rev Feb 14,2022)	Response to IRs May 2, 2022	Variance over Original Filing	Settlement Proposal June 24 2022	Variance over IRs
Residential	2,345	2,345	0	2,345	0
General Service < 50 kW	165	165	0	165	0
General Service > 50 to 4999 kW	9	9	0	9	0
Unmetered Scattered Load	17	17	0	17	0
Street Lighting	633	633	0	633	0
Total	3,168	3,168	0	3,168	0

Evidence References

- EXHIBIT 3 – Load and Customer Forecast

IR Responses

- No IRs

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.1.2 Load Forecast

Full Settlement

The Parties agree to CHEI's Load Forecast Model, as updated pursuant to the adjustments described under issue 3.1, as detailed in Table 13 below.

Table 13 - Summary of 2023 Load Forecast (kWh & kW)

Particulars	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24 2022**	**Variance over IRs**
(kWh)					
Residential	20,126,172	20,150,710	24,538	20,274,072	123,362
General Service < 50 kW	4,617,010	4,620,558	3,547	4,620,092	-466
General Service > 50 to 4999 kW	3,952,566	3,960,295	7,729	3,959,895	-399
Unmetered Scattered Load	93,084	88,338	-4,746	88,338	0
Street Lighting	241,169	242,877	1,708	234,836	-8,041
	29,030,001	**29,062,778**	**32,777**	**29,177,234**	**114,456**
(kW)					
Residential	0	0	0	0	0
General Service < 50 kW	0	0	0	0	0
General Service > 50 to 4999 kW	11,425	11,414	-10	11,413	-1
Unmetered Scattered Load	0	0	0	0	0
Street Lighting	652	655	3	655	0
	12,077	**12,069**	**-7**	**12,068**	**-1**

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 3 – Load and Customer Forecast

IR Responses

- 3-Staff-44-48
- 3-VECC-10-14

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.1.3 Loss Factors

Full Settlement

The Parties have agreed for the purpose of settlement that the 2023 forecast loss factor is appropriate.

Table 14 - 2023 Loss Factors

Particulars	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24 2022**	**Variance over IRs**
Loss Factor in Distributor's system = C / F	1.0479	1.0479	0.0000	1.0479	0.0000
Losses Upstream of Distributor's System					
Supply Facilities Loss Factor	1.0340	1.0340	0.0000	1.0340	0.0000
Total Losses					
Total Loss Factor = G x H	1.0835	1.0835	0.0000	1.0835	0.0000

Evidence References

- EXHIBIT 8 – Rate Design
- EXHIBIT 8 – Loss Factor

IR Responses

- 8-VECC-31
- 9-Staff-84

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios, appropriate?

Full Settlement

The Parties agree to make the following adjustments to CHEI's proposed cost allocation methodology, allocations, and revenue-to-cost ratios:

a) The Parties have agreed to the use of historical HONI based load profiles for the purposes of the allocation of costs in combination with a five-year average of the load profiles historically used by CHEI for its USL class, as set out in interrogatories 7-VECC-28 c) and 7-Staff-75,

b) The Parties agree that CHEI proposed adjustments to the calculated Revenue to Cost ratios after updating those ratios to reflect all the other elements of the Settlement Proposal, were determined in accordance with OEB policy and are appropriate.

c) The Parties agree that CHEI proposed fixed to variable split, after updating those ratios to reflect all the other elements of the Settlement Proposal, were determined in accordance with OEB policy and are appropriate.

The Parties agree that as part of its next Cost of Service application, CHEI will undertake a study to establish CHEI specific load profiles using CHEI metering data for the purposes of an updated allocation of costs.

Table 15 – Summary of 2023 Revenue-to-Cost Ratios

Particulars	**Jan 31, 2022 (rev Feb 14,2022)**			**Response to IRs May 2, 2022**			**Settlement Proposal June 24 2022**		
Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Var	Calculated R/C Ratio	Proposed R/C Ratio	Var	Calculated R/C Ratio	Proposed R/C Ratio	Var
Residential	1.01	1.00	0.01	1.01	1.00	0.00	1.00	1.00	0.00
General Service < 50 kW	0.96	0.96	0.00	0.97	0.97	0.00	1.00	1.00	0.00
General Service > 50 to 4999 kW	0.87	0.96	-0.09	0.90	0.97	-0.07	0.93	0.96	-0.03
Unmetered Scattered Load	1.52	1.20	0.32	1.51	1.20	0.31	1.99	1.20	0.79
Street Lighting	1.11	1.11	0.00	1.14	1.14	0.00	1.17	1.17	0.00

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 7 – Cost Allocation

IR Responses

- No IRs

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.3 Are Cooperative Hydro Embrun's proposals, including the proposed fixed/variable splits, for rate design appropriate?

Full Settlement

For the purposes of settlement, the Parties agree that the proposed Fixed and Variable rates as updated through the settlement process are reasonable and in accordance with OEB policy.

Table 17 below sets out the final fixed and variable rates for all classes pursuant to the Settlement Proposal.

Table 16 – Summary of 2023 Fixed to Variable Split

Particulars		**Jan 31, 2022 (rev Feb 14,2022)**	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Response to IRs May 2, 2022**	**Settlement Proposal June 24 2022**	**Settlement Proposal June 24 2022**
Customer Class Name	**per**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**
Residential	kWh	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
General Service < 50 kW	kWh	33.83%	66.17%	33.81%	66.19%	33.82%	66.18%
General Service > 50 to 4999 kW	kW	29.84%	70.16%	29.86%	70.14%	29.87%	70.13%
Unmetered Scattered Load	kW	75.78%	24.22%	76.73%	23.27%	76.73%	23.27%
Street Lighting	kW	56.22%	43.78%	56.11%	43.89%	56.11%	43.89%

Table 17 - 2023 Distribution Rates

Particulars		**Jan 31, 2022 (rev Feb 14,2022)**	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Response to IRs May 2, 2022**	**Settlement Proposal June 24 2022**	**Settlement Proposal June 24 2022**
Customer Class Name	**per**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**
Residential	kWh	$33.66	$0.0000	$34.88	$0.0000	$33.93	$0.0000
General Service < 50 kW	kWh	$20.19	$0.0169	$20.89	$0.0175	$20.25	$0.0169
General Service > 50 to 4999 kW	kW	$193.82	$4.1192	$197.39	$4.1951	$182.81	$3.8852
Unmetered Scattered Load	kW	$16.18	$0.0111	$16.96	$0.0116	$12.30	$0.0084
Street Lighting	kW	$2.14	$19.4273	$2.21	$20.0707	$2.14	$19.4100

Evidence References

- EXHIBIT 8 - Rate Design

IR Responses

- 8-Staff-77-78
- 8-VECC-30

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.4 Are the proposed Retail Transmission Service and Low Voltage Rates appropriate?

Full Settlement

The Parties have agreed to the RTSR rates and low voltage rates as presented in Table 18 and Table 19 below. The Parties note that the current (2022) UTRs have been used in the determination of the RTSRs. The Parties agree that the UTR's will be updated to reflect the OEB's approved UTR's for 2023 if available at the time the final draft order is issued.

Table 18 - 2023 RTSR Network and Connection Rates Charges

	Jan 31, 2022 (rev Feb 14,2022)	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Response to IRs May 2, 2022**	**Settlement Proposal June 24 2022**	**Settlement Proposal June 24 2022**
Transmission - Network						
Class Name	**Rate**	**Impact on CoP**	**Rate**	**Impact on CoP**	**Rate**	**Impact on CoP**
Residential	0.0077	$167,571	0.0097	$212,107	0.0093	$204,072
General Service < 50 kW	0.0070	$34,669	0.0088	$43,863	0.0084	$42,277
General Service > 50 to 4999 kW	2.8324	$32,293	3.5735	$40,789	3.4172	$39,001
Unmetered Scattered Load	0.0070	$700	0.0088	$839	0.0084	$808
Street Lighting	2.1362	$1,339	2.6952	$1,765	2.5773	$1688
		$236,572		**$299,364**		**$287,846**
Transmission - Connection						
Class Name	**Rate**	**Impact on CoP**	**Rate**	**Impact on CoP**	**Rate**	**Impact on CoP**
Residential	0.0065	$141,456	0.0069	$150,872	0.0066	$145,277
General Service < 50 kW	0.0056	$27,735	0.0060	$29,568	0.0057	$28,522
General Service > 50 to 4999 kW	2.2699	$25,880	2.4131	$27,544	2.3095	$26,359
Unmetered Scattered Load	0.0056	$560	0.0060	$565	0.0057	$545
Street Lighting	1.7547	$1,100	1.8654	$1,222	1.7853	$1,169
		$196,731		**$209,772**		**$201,873**

Table 19 - 2023 Low Voltage Rates

Transmission - Network	**Jan 31, 2022 (rev Feb 14,2022)**	**Jan 31, 2022 (rev Feb 14,2022)**	**Response to IRs May 2, 2022**	**Response to IRs May 2, 2022**	**Settlement Proposal June 24 2022**	**Settlement Proposal June 24 2022**
Class Name	Rate	Impact on CoP	Rate	Impact on CoP	Rate	Impact on CoP
Residential	$0.0049	$98,038	$0.0041	$83,010	$0.0043	$87,185
General Service < 50 kW	$0.0042	$19,222	$0.0035	$16,268	$0.0037	$17,117
General Service > 50 to 4999 kW	$1.5700	$17,937	$1.3277	$15,155	$1.3860	$15,818
Unmetered Scattered Load	$0.0042	$388	$0.0035	$311	$0.0037	$327
Street Lighting	$1.2136	$791	$1.0263	$672	$1.0714	$702
		$136,376		**$115,416**		**$121,149**

Evidence References

- EXHIBIT 8 - Rate Design
- EXHIBIT 8 - RTSR

IR Responses

- 8-VECC-29
- VECC-39 to 40

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

3.5 Are the Specific Service Charges, Retail Service Charges, and Pole Attachment Charge appropriate?

Full Settlement

The Parties agree that CHEI's proposed Specific Service Charges, Retail Service Charges and Pole Attachment Charge are appropriate, and properly reflect the OEB's Decision regarding 2022 Retail Services Charges as applicable. The Parties agree that the Retail Service Charges and Pole Attachment charge will be updated to reflect the OEB's approved charges for 2023 if available at the time the final order is issued. If the OEB-approved charges for 2023 are not available at the time the final rate order is issued, CHEI will adopt the generic orders of the OEB as required.

Evidence References

- EXHIBIT 8 - Rate Design

IR Responses

- 6-Staff-71
- 6-VECC-25
- 8-Staff-79
- 8-Staff-103to 104

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

4.0 ACCOUNTING

4.1 Have all impacts of any changes in accounting standards, policies, estimates, and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

Full Settlement

The Parties agree that all impacts of any changes to accounting standards, policies, estimates, and adjustments identified by CHEI in the Application and the interrogatories have been properly identified, recorded and have been treated appropriately in the rate-making process.

Evidence References

- EXHIBIT 1 – Administrative Documents

IR Responses

- 2-Staff-38
- 6-Staff-63-66-67
- 9-Staff-85-86-89
- 9-VECC-33

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

4.2 Are Cooperative Hydro Embrun's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?

Full Settlement

The Parties agree that CHEI's proposals for deferral and variance accounts are appropriate, including the proposed disposition of those accounts on a final basis as shown in Table 20, subject to the following revisions:

a) Please refer to section 5.3 and Appendix D of this settlement proposal regarding Account 1588 and Account 1589.

b) The Parties note that CHEI has withdrawn its Account 1568 LRAMVA claim, as well as its Account 1592, PILs and Tax Variances, Sub-Account Deferred Taxes claim.

c) The Parties note that while they do not necessarily agree on the methodology used by CHEI to determine the amounts tracked in Account 1592, Sub-Account CCA Changes regarding accelerated CCA, the parties agree that the resulting credit of -$4,999 to ratepayers calculated to the end of 2021 is appropriate.

d) The Parties agree that Account 1592, Sub-Account CCA Changes will remain open to capture the phase-out of accelerated CCA (which is currently anticipated to begin after 2023) and to capture any future changes in the current tax laws and rules governing CCA , beyond those contemplated in the current proceeding.

e) The Parties agree with the subsequent closing of these accounts effective January 1, 2023:

- Account 1508, Sub-Account Pole Attachment Revenue Variance
- Account 1508, Sub-Account Retail Service Charge Incremental Revenue

f) Although balances for the following accounts pertaining to the 2022 calendar year would typically be forecasted and disposed in the current application, the Parties agree that these actual balances (and not forecasted balances) will be disposed in CHEI's next cost of service application:

- Account 1508, Sub-account Pole Attachment Revenue Variance
- Account 1508, Sub-account Retail Service Charge Incremental Revenue
- Account 1592, Sub-account, CCA Changes

Table 20 - DVA Balances for Disposition

			January 31, 2022 (Rev February 14, 2022)	**Response to IRs May 2, 2022**	**Variance over Original Application**	**Settlement Proposal June 24, 2022**	**Variance over IRs**
Group 1 DVAs							
1550	LV Variance Account		$20,849	$20,742	$(108)	$20,742	$-
1551	Smart Metering Entity Charge Variance Account		$(1,631)	$(1,396)	$235	$(1,396)	$-
1580	RSVA - Wholesale Market Service Charge		$(14,407)	$(13,857)	$551	$(13,857)	$-
1584	RSVA - Retail Transmission Network Charge		$14,678	$11,070	$(3,607)	$11,070	$-
1586	RSVA - Retail Transmission Connection Charge		$9,575	$6,814	$(2,761)	$6,814	$-
1588	RSVA - Power		$(40,736)	$(38,361)	$2,375	$(38,361)	$-
1589	RSVA - Global Adjustment		$3,611	$(10,695)	$(14,306)	$(10,695)	$-
1595	Disposition and Recovery/Refund of Regulatory Balances (2019)		$-	$-	$-	$(154)	$(154)
Sub-total			$(8,061)	$(25,682)	$(17,621)	$(25,835)	$(154)
Sub-total (excluding Account 1589)			$(11,672)	$(14,987)	$(3,315)	$(15,141)	$(154)
Group 2 DVAs							
1508	Pole Attachment Revenue Variance		$(17,775)	$(17,775)	$-	$(17,775)	$-
1508	Retail Service Charge Incremental Revenue		$(6,838)	$(6,951)	$(113)	$(6,951)	$-
1508	Customer Choice Initiative Costs		$8,096	$8,096	$-	$8,096	$-
1592	PILs and Tax Variances, Deferred Taxes		$80,207	$-	$(80,207)	$-	$-
1592	PILs and Tax Variances, CCA Changes		$4,725	$(4,725)	$(9,450)	$(4,999)	$(274)
Sub-total			$68,415	$(21,355)	$(89,770)	$(21,629)	$(274)
Other DVAs							
1568	LRAMVA		$(752)	$-	$752	$-	$-
Total			$59,602	$(47,037)	$(106,640)	$(47,465)	$(428)

Evidence References

- EXHIBIT 9 – DVA

IR Responses

- 9-Staff-81 to 90
- 9-VECC-33
- 9-Staff-105 to 108

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

5.0 OTHER

5.1 Is the proposed effective date (i.e., January 1, 2023) for 2023 rates appropriate?

Full Settlement

The Parties agree that CHEI's new rates should be effective on January 1, 2023.

The Parties note that the very early filing and resolution of this application including, if accepted, this Settlement Proposal means that many of the "pass through" elements that are to be included in the final rate order have yet to be updated by the OEB for the 2023 test year. Accordingly, the Parties have agreed to placeholders for these elements in the Settlement Proposal using the existing, 2022 OEB approved values. The Parties further agree that those elements will be updated as part of the process to update the approved draft rate order provided that those elements are available to the Parties in sufficient time to update the draft rate order, submit it the OEB for approval and for the OEB to issue a final rate order in time for January 1, 2023 implementation.

The elements that the Parties expect to be able to update as part of the final rate order include the following as applicable:

a) the OEB's approved Cost of Capital parameters (ROE, deemed long-term debt rate and deemed short-term debt rate) for 2023 test year applications.

b) the Retail Service Charges and Pole Attachment Charge for 2023.

c) the OEB approved Uniform Transmission Rates for 2023,

d) the updated Ontario Energy Rebate amount effective January 1, 2023,

e) updates to the Regulated Price Plan effective January 1, 2023 (the Parties note that the draft rate order is currently based on the OEB's Regulated Price Plan Report for November 1, 2021, to October 31, 2022); and

f) the updated working capital calculation to the extent it is impacted by the various other updates e.g., the updated OER.

Evidence References

- EXHIBIT 1 – Administrative Documents

IR Responses

- None

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

5.2 Is the continuation of Cooperative Hydro Embrun's $10 utility-specific MicroFit rate appropriate?

Full Settlement

The Parties agree that the continuation of the proposed $10 utility specific MicroFit rate is appropriate.

Evidence References

- EXHIBIT 6 – Revenue Requirement

IR Responses

- 4-Staff-51
- 6-Staff-72-73
- 6-VECC-25
- 3-VECC-10-13

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

5.3 Has Cooperative Hydro Embrun responded appropriately to the prior commitment from its 2018 Cost of Service settlement proposal (EB-2017-0035) relating to line losses and to the OEB's direction in EB-2020-0011 to provide an update in its 2022 rate application with respect to its adoption of the OEB's accounting guidance?

Full Settlement

With respect to line losses the Parties acknowledge that the construction of a new Station in 2017, followed by the impacts of the pandemic in the 2020 to 2022 period, have made a thorough follow up by CHEI into the issue of line losses impractical. To address that issue the Parties agree that CHEI should complete, within the rate period, a line loss study and implement related measures to mitigate line losses going forward where practical. To that end, and as noted under issue 1.1, the Parties have agreed to provide $36,000 in capitalized funding in CHEI's rate base for the purposes of commissioning a line loss study and for the implementation of measures recommended by that study as applicable and where reasonable. It is expected that the line loss study and the response to that study will be included in CHEI's next cost of service application.

With respect to the adoption of the OEB's accounting guidance as it relates to the clearance of amounts out of Accounts 1588 and 1589, the Parties note that OEB staff identified four issues of concern with respect to how CHEI's accounting for 1588 and 1589 differed from the OEB's accounting guidance.[1] At Appendix D to this Settlement Proposal CHEI has summarized these four issues.

Parties have reviewed the explanations for these four issues and noted that there do not appear to be any further issues regarding Issue #3 and Issue #4 in Appendix D. Parties made the following two observations regarding Issue #1 and Issue #2:

Regarding Issue #1 for the allocation of the micro-fit generation consumption, Parties noted that there appears to be a mismatch of the GA volumes charged by Hydro One and the allocated GA volumes to CHEI's RPP and Non-RPP customers. CHEI states that it recognizes that the percentage allocation determined by CHEI does not include the embedded generation and the impact of the embedded generation volumes over RPP and Non-RPP established volumes would be trivial over the allocation percentage. (represents 0.3106% for one year's consumption).[2]

> Parties noted that this mismatch does not conform to the OEB's accounting guidance. However, as indicated by CHEI's response, the impact of this mismatch is minimal as of the date of this settlement proposal and would likely remain minimal moving forward if the micro-fit generation consumption remains stable.

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[1] Accounting Procedures Handbook (APH) Update, Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019

[2] Appendix D, page XX.

- Regarding Issue #2 for the RPP settlement with Hydro One (Bill 100 adjustment), CHEI indicates that it calculates the RPP portion of global adjustment on BILL 100 Adjustment form using "Provincial benefit Power Bill (minus) Amount collected from Spot Customers". However, parties noted that this process may not conform to the OEB's accounting guidance because the RPP portion of global adjustment should be calculated as the GA actual rate for the month multiplied by actual Volumes purchased for RPP Customers (this is illustrated in OEB's commodity illustrative model Tab. "RPP 2nd TU", Table Final RPP Settlement Calculation on Business Day 4 of March 2018). Parties noted that the resulted difference between the OEB's approach and CHEI's approach may be minimal as at a point of time.

In addition, CHEI stated in Appendix D that "1588 variances are calculated based on the difference between the GA Invoiced for RPP customers and the GA billed to RPP customers" and "the GA Adjustment Billed to RPP Customers consists of the Power Billed to Customers less the Power Bill from Hydro One, all of which relates to RPP customers". Parties noted that CHEI's definition of Account 1588 variances and GA billed to RPP customers are not in line with the OEB's accounting guidance. The OEB's accounting guidance issued in February 2019 states that "the balances accumulated in Account 1588 - RSVAPower are caused by all of a distributor's electricity customers, with the exception of embedded wholesale market participants".[3] CHEI's approach for Account 1588 variance indicates that the line loss for Non-RPP customers is not accounted for in account 1588. In addition, the GA billed to the RPP customers should not be calculated using the back of envelop approach as did by CHEI. Instead, it should be calculated as the sum of the global adjustment actual rate for the month multiplied by the associated RPP volumes (TOU or two tiers).

. Parties noted that due to the limited size of CHEI (a total of 3,168 customers), these impacts might also be minimal.

For the above two issues, Parties are of the view that Account 1588 and Account 1589 can still be cleared on a final basis given the relatively small balances (-$38,360 and -$10,694) and because the area of non-conformity does not appear to result in significant impacts on CHEI's accounting and RPP settlement process.

- In Appendix D, CHEI stated that:

> It is our belief that, following OEB's guidance in 2020, CHEI and BDO have improved the process given the circumstances of CHEI's customer base and have been able to perform the analysis of 1588 / 1589 in a way that agrees with OEB's accounting guidance.

Although there are a number of non-conformity area noted in Appendix D, parties agree that there is no further requirement for CHEI to address the four issues in future rate applications if CHEI's operational circumstance regarding the embedded generation and the number of

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[3] The OEB's Accounting Guidance, February 21, 2019, page 1.

customers remain stable. However, if any of these two circumstances changes (i.e., CHEI has increased embedded generation and/or increased the number of customers significantly), Parties agree that there is a need for CHEI at that time to reassess the impact of Issue #1 and Issue #2.

Parties also acknowledge that consistent with the generic approach set out in the OEB's 2019 letter regarding retroactive adjustments to correct for errors,[4] CHEI is responsible for its accounting and if in the future, material discrepancies arise due to accounting or other errors made by CHEI, an asymmetrical approach to the correction of the error(s) may be appropriate when disposing of future balances.

Lastly, Parties agree that moving forward, CHEI is encouraged to provide its internal existing reconciliation sheet(s) for Accounts 1588 and 1589 to assist the OEB to make decisions whenever CHEI requests the disposition of these two commodity variance accounts in its rate applications.

Evidence References

- EXHIBIT 8 – Rate Design

IR Responses

- 8-Staff-0.4.1

Supporting Parties

- VECC, OEB Staff

Parties Taking No Position

- None

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[4] OEB Letter, Adjustments to Correct for Errors in Electricity Distributor "Pass-Through" Variance Accounts After Disposition, October 31, 2019

6 ATTACHMENTS

Appendix A	Proposed January 1, 2023, Tariff of Rates and Charges
Appendix B	Bill Impacts
Appendix C	Revenue Requirement Work Form
Appendix D	Summary of Accounting Guidance of accounts 1588/1589

A Proposed January 1, 2023, Tariff of Rates and Charges

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0022

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.93
Rate Rider for Dispostion of Group 2 Deferral and Variance Accounts - effective until December 31, 2023	$	(0.62)
Smart Metering Entity Charge - Approved on an Interim Basis	$	0.43
Low Voltage Service Rate	$/kWh	0.0043
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2023	$/kWh	(0.0005)
Rate Rider for RSVA - Power-Global Adjustment (applicable only to non-RPP customers) - effective until December 31, 2023	$/kWh	(0.0023)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0093
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0066

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

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EB-2022-0022

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.25
Smart Metering Entity Charge - Approved on an Interim Basis	$	0.43
Distribution Volumetric Rate	$/kWh	0.0169
Low Voltage Service Rate	$/kWh	0.0037
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2023	$/kWh	(0.0005)
Rate Rider for Dispostion of Group 2 Deferral and Variance Accounts - effective until December 31, 2023	$/kW	(0.0004)
Rate Rider for RSVA - Power-Global Adjustment (applicable only to non-RPP customers) - effective until December 31, 2023	$/kWh	(0.0023)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0084
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0057

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0022

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	182.81
Distribution Volumetric Rate	$/kW	3.8852
Low Voltage Service Rate	$/kW	1.3860
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2023	$/kW	(0.1635)
Rate Rider for Dispostion of Group 2 Deferral and Variance Accounts - effective until December 31, 2023	$/kW	(0.0491)
Rate Rider for RSVA - Power-Global Adjustment (applicable only to non-RPP customers) - effective until December 31, 2023	$/kWh	(0.0023)
Retail Transmission Rate - Network Service Rate	$/kW	3.4172

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3095

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	12.30
Distribution Volumetric Rate	$/kWh	0.0084
Low Voltage Service Rate	$/kWh	0.0037
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2023	$/kWh	(0.0005)
Rate Rider for Dispostion of Group 2 Deferral and Variance Accounts - effective until December 31, 2023	$/kWh	(0.0009)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0084
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0057

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2022-0022

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.14
Distribution Volumetric Rate	$/kW	19.4100
Low Voltage Service Rate	$/kW	1.0714
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2023	$/kW	(0.1687)
Rate Rider for Dispostion of Group 2 Deferral and Variance Accounts - effective until December 31, 2023	$/kW	(2.7562)
Rate Rider for RSVA - Power-Global Adjustment (applicable only to non-RPP customers) - effective until December 31, 2023	$/kWh	(0.0023)
Retail Transmission Rate - Network Service Rate	$/kW	2.5773
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7853

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0022

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10.00

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit check (plus credit agency costs)	$	25.00

Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	25.00
Reconnection at meter - after regular hours	$	50.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after hours	$	415.00

Other

Special meter reads	$	20.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service - installation and removal - overhead - no transformer	$	500.00
Temporary service - installation and removal - underground - no transformer	$	300.00
Temporary service - installation and removal - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	34.76

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of Ontario Energy Board, and amendments thereto as approved by Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	107.68
Monthly fixed charge, per retailer	$	43.08
Monthly variable charge, per customer, per retailer	$/cust.	1.07
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.64
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.64)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.54
Processing fee, per request, applied to the requesting party	$	1.07
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge

More than twice a year, per request (plus incremental delivery costs)	$	4.31
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.15

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0835
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0835

B Bill Impacts

Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2022 Cost of Service Filers)

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:

1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1101/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

🟨 Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor (eg: 1.0351)**	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0749	1.0835	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0749	1.0835	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Retailer)	1.0749	1.0835	33,000	80	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0749	1.0835	400		CONSUMPTION	
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0749	1.0835	30,000	48	DEMAND	503
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0749	1.0835	750		CONSUMPTION	
Add additional scenarios if required								
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Table 2

RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**Sub-Total**						**Total**	
		A		**B**		**C**		**Total Bill**	
		$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	-$4.13	-11.0%	-$3.09	-6.7%	-$1.62	-2.8%	-$1.53	-1.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	-$6.49	-10.9%	-$4.12	-5.1%	-$0.65	-0.6%	-$0.56	-0.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kW	-$36.03	-6.9%	-$100.72	-16.4%	-$50.77	-5.0%	-$20.81	-0.4%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	-$3.12	-51.0%	-$2.62	-24.8%	-$1.93	-12.1%	-$1.84	-3.1%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	-$339.32	-15.3%	-$405.15	-18.0%	-$382.51	-15.7%	-$399.00	-5.8%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	-$4.13	-11.0%	-$4.77	-10.3%	-$3.30	-5.7%	-$3.14	-2.3%

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption 750 kWh
Demand - kW
Current Loss Factor 1.0749
Proposed/Approved Loss Factor 1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 37.44	1	$ 37.44	$ 33.93	1	$ 33.93	$ (3.51)	-9.38%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ (0.62)	1	$ (0.62)	$ (0.62)	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 37.44**			**$ 33.31**	**$ (4.13)**	**-11.03%**
Line Losses on Cost of Power	$ 0.1031	56	$ 5.79	$ 0.1031	63	$ 6.46	$ 0.67	11.48%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ (0.0005)	750	$ (0.38)	$ (0.38)	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0033	750	$ 2.48	$ 0.0043	750	$ 3.23	$ 0.75	30.30%
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 46.14**			**$ 43.05**	**$ (3.09)**	**-6.70%**
RTSR - Network	$ 0.0077	806	$ 6.21	$ 0.0093	813	$ 7.56	$ 1.35	21.75%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	806	$ 5.24	$ 0.0066	813	$ 5.36	$ 0.12	2.35%
Sub-Total C - Delivery (including Sub-Total B)			**$ 57.58**			**$ 55.97**	**$ (1.62)**	**-2.81%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	806	$ 2.74	$ 0.0034	813	$ 2.76	$ 0.02	0.80%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	806	$ 0.40	$ 0.0005	813	$ 0.41	$ 0.00	0.80%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	488	$ 39.98	$ 0.0820	488	$ 39.98	$ -	0.00%
TOU - Mid Peak	$ 0.1130	128	$ 14.41	$ 0.1130	128	$ 14.41	$ -	0.00%
TOU - On Peak	$ 0.1700	135	$ 22.95	$ 0.1700	135	$ 22.95	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 138.31**			**$ 136.72**	**$ (1.59)**	**-1.15%**
HST	13%		$ 17.98	13%		$ 17.77	$ (0.21)	-1.15%
Ontario Electricity Rebate	17.0%		$ (23.51)	17.0%		$ (23.24)	$ 0.27	
Total Bill on TOU			**$ 132.78**			**$ 131.25**	**$ (1.53)**	**-1.15%**

In the manager's summary, discuss the reaso

Customer Class: GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption 2,000 kWh
Demand - kW
Current Loss Factor 1.0749
Proposed/Approved Loss Factor 1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 22.34	1	$ 22.34	$ 20.25	1	$ 20.25	$ (2.09)	-9.36%
Distribution Volumetric Rate	$ 0.0187	2000	$ 37.40	$ 0.0169	2000	$ 33.80	$ (3.60)	-9.63%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ (0.0004)	2000	$ (0.80)	$ (0.80)	
Sub-Total A (excluding pass through)			**$ 59.74**			**$ 53.25**	**$ (6.49)**	**-10.86%**
Line Losses on Cost of Power	$ 0.1031	150	$ 15.45	$ 0.1031	167	$ 17.22	$ 1.77	11.48%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ (0.0005)	2,000	$ (1.00)	$ (1.00)	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0029	2,000	$ 5.80	$ 0.0037	2,000	$ 7.40	$ 1.60	27.59%
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 81.42**			**$ 77.30**	**$ (4.12)**	**-5.06%**
RTSR - Network	$ 0.0070	2,150	$ 15.05	$ 0.0084	2,167	$ 18.20	$ 3.15	20.96%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	2,150	$ 12.04	$ 0.0057	2,167	$ 12.35	$ 0.31	2.60%
Sub-Total C - Delivery (including Sub-Total B)			**$ 108.50**			**$ 107.85**	**$ (0.65)**	**-0.60%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,150	$ 7.31	$ 0.0034	2,167	$ 7.37	$ 0.06	0.80%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,150	$ 1.07	$ 0.0005	2,167	$ 1.08	$ 0.01	0.80%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	1,300	$ 106.60	$ 0.0820	1,300	$ 106.60	$ -	0.00%
TOU - Mid Peak	$ 0.1130	340	$ 38.42	$ 0.1130	340	$ 38.42	$ -	0.00%
TOU - On Peak	$ 0.1700	360	$ 61.20	$ 0.1700	360	$ 61.20	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 323.36**			**$ 322.78**	**$ (0.58)**	**-0.18%**
HST	13%		$ 42.04	13%		$ 41.96	$ (0.08)	-0.18%
Ontario Electricity Rebate	17.0%		$ (54.97)	17.0%		$ (54.87)	$ 0.10	
Total Bill on TOU			**$ 310.42**			**$ 309.86**	**$ (0.56)**	**-0.18%**

In the manager's summary, discuss the reaso

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	**33,000** kWh
Demand	**80** kW
Current Loss Factor	**1.0749**
Proposed/Approved Loss Factor	**1.0835**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 194.70	1	$ 194.70	$ 182.81	1	$ 182.81	$ (11.89)	-6.11%
Distribution Volumetric Rate	$ 4.1379	80	$ 331.03	$ 3.8852	80	$ 310.82	$ (20.22)	-6.11%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	80	$ -	$ (0.0491)	80	$ (3.93)	$ (3.93)	
Sub-Total A (excluding pass through)			**$ 525.73**			**$ 489.70**	**$ (36.03)**	**-6.85%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	80	$ -	$ (0.1635)	80	$ (13.08)	$ (13.08)	
CBR Class B Rate Riders	$ -	80	$ -	$ -	80	$ -	$ -	
GA Rate Riders	$ -	33,000	$ -	$ (0.0023)	33,000	$ (75.90)	$ (75.90)	
Low Voltage Service Charge	$ 1.0823	80	$ 86.58	$ 1.3860	80	$ 110.88	$ 24.30	28.06%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		80	$ -	$ -	80	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 612.32**			**$ 511.60**	**$ (100.72)**	**-16.45%**
RTSR - Network	$ 2.8324	80	$ 226.59	$ 3.4172	80	$ 273.38	$ 46.78	20.65%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2699	80	$ 181.59	$ 2.3095	80	$ 184.76	$ 3.17	1.74%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,020.50**			**$ 969.73**	**$ (50.77)**	**-4.97%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	35,472	$ 120.60	$ 0.0034	35,756	$ 121.57	$ 0.96	0.80%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	35,472	$ 17.74	$ 0.0005	35,756	$ 17.88	$ 0.14	0.80%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	35,472	$ 3,905.43	$ 0.1101	35,756	$ 3,936.68	$ 31.25	0.80%
Total Bill on Non-RPP Avg. Price			**$ 5,064.27**			**$ 5,045.86**	**$ (18.41)**	**-0.36%**
HST	13%		$ 658.36	13%		$ 655.96	$ (2.39)	-0.36%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 5,722.63**			**$ 5,701.82**	**$ (20.81)**	**-0.36%**

In the manager's summary, discuss the reaso

Customer Class: UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP: Non-RPP (Retailer)
Consumption 400 **kWh**
Demand - **kW**
Current Loss Factor 1.0749
Proposed/Approved Loss Factor 1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 22.39		$ -	$ 12.30	0	$ -	$ -	
Distribution Volumetric Rate	$ 0.0153	400	$ 6.12	$ 0.0084	400	$ 3.36	$ (2.76)	-45.10%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	400	$ -	$ (0.0009)	400	$ (0.36)	$ (0.36)	
Sub-Total A (excluding pass through)			**$ 6.12**			**$ 3.00**	**$ (3.12)**	**-50.98%**
Line Losses on Cost of Power	$ 0.1101	30	$ 3.30	$ 0.1101	33	$ 3.68	$ 0.38	11.48%
Total Deferral/Variance Account Rate Riders	$ -	400	$ -	$ (0.0005)	400	$ (0.20)	$ (0.20)	
CBR Class B Rate Riders	$ -	400	$ -	$ -	400	$ -	$ -	
GA Rate Riders	$ -	400	$ -	$ -	400	$ -	$ -	
Low Voltage Service Charge	$ 0.0029	400	$ 1.16	$ 0.0037	400	$ 1.48	$ 0.32	27.59%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		400	$ -	$ -	400	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 10.58**			**$ 7.96**	**$ (2.62)**	**-24.78%**
RTSR - Network	$ 0.0070	430	$ 3.01	$ 0.0084	433	$ 3.64	$ 0.63	20.96%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	430	$ 2.41	$ 0.0057	433	$ 2.47	$ 0.06	2.60%
Sub-Total C - Delivery (including Sub-Total B)			**$ 16.00**			**$ 14.07**	**$ (1.93)**	**-12.05%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	430	$ 1.46	$ 0.0034	433	$ 1.47	$ 0.01	0.80%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	430	$ 0.21	$ 0.0005	433	$ 0.22	$ 0.00	0.80%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	400	$ 44.04	$ 0.1101	400	$ 44.04	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 61.71**			**$ 59.80**	**$ (1.91)**	**-3.10%**
HST	13%		$ 8.02	13%		$ 7.77	$ (0.25)	-3.10%
Ontario Electricity Rebate	17.0%		$ (10.49)	17.0%		$ (10.17)		
Total Bill on Non-RPP Avg. Price			**$ 59.24**			**$ 57.41**	**$ (1.84)**	**-3.10%**

In the manager's summary, discuss the reaso

Customer Class: STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP: Non-RPP (Other)
Consumption 30,000 kWh
Demand 48 kW
Current Loss Factor 1.0749
Proposed/Approved Loss Factor 1.0835

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 2.36	503	$ 1,187.08	$ 2.14	503	$ 1,076.42	$ (110.66)	-9.32%
Distribution Volumetric Rate	$ 21.4175	48	$ 1,028.04	$ 19.4100	48	$ 931.68	$ (96.36)	-9.37%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	48	$ -	$ (2.7562)	48	$ (132.30)	$ (132.30)	
Sub-Total A (excluding pass through)			**$ 2,215.12**			**$ 1,875.80**	**$ (339.32)**	**-15.32%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	48	$ -	$ (0.1687)	48	$ (8.10)	$ (8.10)	
CBR Class B Rate Riders	$ -	48	$ -	$ -	48	$ -	$ -	
GA Rate Riders	$ -	30,000	$ -	$ (0.0023)	30,000	$ (69.00)	$ (69.00)	
Low Voltage Service Charge	$ 0.8367	48	$ 40.16	$ 1.0714	48	$ 51.43	$ 11.27	28.05%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		48	$ -	$ -	48	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2,255.28**			**$ 1,850.13**	**$ (405.15)**	**-17.96%**
RTSR - Network	$ 2.1362	48	$ 102.54	$ 2.5773	48	$ 123.71	$ 21.17	20.65%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7547	48	$ 84.23	$ 1.7853	48	$ 85.69	$ 1.47	1.74%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,442.04**			**$ 2,059.54**	**$ (382.51)**	**-15.66%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	32,247	$ 109.64	$ 0.0034	32,505	$ 110.52	$ 0.88	0.80%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	32,247	$ 16.12	$ 0.0005	32,505	$ 16.25	$ 0.13	0.80%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	32,247	$ 3,550.39	$ 0.1101	32,505	$ 3,578.80	$ 28.41	0.80%
Total Bill on Average IESO Wholesale Market Price			**$ 6,118.45**			**$ 5,765.36**	**$ (353.10)**	**-5.77%**
HST	13%		$ 795.40	13%		$ 749.50	$ (45.90)	-5.77%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 6,913.85**			**$ 6,514.85**	**$ (399.00)**	**-5.77%**

In the manager's summary, discuss the reaso

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: Non-RPP (Retailer)
Consumption 750 kWh
Demand - kW
Current Loss Factor 1.0749
Proposed/Approved Loss Factor 1.0835

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 37.44	1	$ 37.44	$ 33.93	1	$ 33.93	$ (3.51)	-9.38%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ (0.62)	1	$ (0.62)	$ (0.62)	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 37.44**			**$ 33.31**	**$ (4.13)**	**-11.03%**
Line Losses on Cost of Power	$ 0.1101	56	$ 6.18	$ 0.1101	63	$ 6.90	$ 0.71	11.48%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ (0.0005)	750	$ (0.38)	$ (0.38)	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ (0.0023)	750	$ (1.73)	$ (1.73)	
Low Voltage Service Charge	$ 0.0033	750	$ 2.48	$ 0.0043	750	$ 3.23	$ 0.75	30.30%
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 46.53**			**$ 41.76**	**$ (4.77)**	**-10.25%**
RTSR - Network	$ 0.0077	806	$ 6.21	$ 0.0093	813	$ 7.56	$ 1.35	21.75%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	806	$ 5.24	$ 0.0066	813	$ 5.36	$ 0.12	2.35%
Sub-Total C - Delivery (including Sub-Total B)			**$ 57.98**			**$ 54.68**	**$ (3.30)**	**-5.69%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	806	$ 2.74	$ 0.0034	813	$ 2.76	$ 0.02	0.80%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	806	$ 0.40	$ 0.0005	813	$ 0.41	$ 0.00	0.80%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	750	$ 82.58	$ 0.1101	750	$ 82.58	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 143.70**			**$ 140.42**	**$ (3.27)**	**-2.28%**
HST	13%		$ 18.68	13%		$ 18.26	$ (0.43)	-2.28%
Ontario Electricity Rebate	17.0%		$ (24.43)	17.0%		$ (23.87)		
Total Bill on Non-RPP Avg. Price			**$ 137.95**			**$ 134.81**	**$ (3.14)**	**-2.28%**

In the manager's summary, discuss the reaso

C Revenue Requirement Work Form

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input (1)

		Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments	Settlement Agreement	
1	**Rate Base**								
	Gross Fixed Assets (average)	$7,185,613		($20,244)	$ 7,165,369		($120,300)	$7,045,069	
	Accumulated Depreciation (average)	($2,708,489)	(5)	($7,332)	($2,715,821)		$2,465	($2,713,355)	
	Allowance for Working Capital:								
	Controllable Expenses	$753,157		$16,738	$ 769,895		$ -	$769,895	
	Cost of Power	$3,293,006		($10,251)	$ 3,282,755		$159,185	$3,441,940	
	Working Capital Rate (%)	7.50%	(9)	0.00%	7.50%	(9)	0.00%	7.50%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$1,289,329		$0	$1,289,329		($13)	$1,289,315	
	Distribution Revenue at Proposed Rates	$1,165,281		$41,016	$1,206,297		($37,822)	$1,168,475	
	Other Revenue:								
	Specific Service Charges	$7,304		$395	$7,699		$0	$7,699	
	Late Payment Charges	$11,450		$0	$11,450		$0	$11,450	
	Other Distribution Revenue	$21,996		($21,504)	$492		$18,480	$18,972	
	Other Income and Deductions	$8,000		$0	$8,000		$0	$8,000	
	Total Revenue Offsets	$48,750	(7)	($21,109)	$27,641		$18,480	$46,121	
	Operating Expenses:								
	OM+A Expenses	$753,157		$16,738	$ 769,895		$ -	$769,895	
	Depreciation/Amortization	$180,507		$11,484	$ 191,991		($3,424)	$188,568	
	Property taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($28,152)	(3)	($48,256)	($76,408)		($69,239)	($145,647)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$16,769		($6,002)	$10,767		($8,895)	$1,872	
	Income taxes (grossed up)	$19,099			$12,263			$2,132	
	Federal tax (%)	9.00%		0.00%	9.00%		0.00%	9.00%	
	Provincial tax (%)	3.20%		0.00%	3.20%		0.00%	3.20%	
	Income Tax Credits								
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%		0.00%	56.0%		0.00%	56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)	0.00%	4.0%	(8)	0.00%	4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%		0.00%	40.0%		0.00%	40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	3.49%		0.00%	3.49%		0.00%	3.49%	
	Short-term debt Cost Rate (%)	1.17%		0.00%	1.17%		0.00%	1.17%	
	Common Equity Cost Rate (%)	8.66%		0.00%	8.66%		0.00%	8.66%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M12. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement
1	Gross Fixed Assets (average)	(2)	$7,185,613	($20,244)	$7,165,369	($120,300)	$7,045,069
2	Accumulated Depreciation (average)	(2)	($2,708,489)	($7,332)	($2,715,821)	$2,465	($2,713,355)
3	Net Fixed Assets (average)	(2)	$4,477,124	($27,576)	$4,449,548	($117,835)	$4,331,714
4	Allowance for Working Capital	(1)	$303,462	$487	$303,949	$11,939	$315,888
5	**Total Rate Base**		$4,780,587	($27,089)	$4,753,497	($105,896)	$4,647,601

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement
6	Controllable Expenses		$753,157	$16,738	$769,895	$ -	$769,895
7	Cost of Power		$3,293,006	($10,251)	$3,282,755	$159,185	$3,441,940
8	Working Capital Base		$4,046,164	$6,487	$4,052,650	$159,185	$4,211,835
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$303,462	$487	$303,949	$11,939	$315,888

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,165,281	$41,016	$1,206,297	($37,822)	$1,168,475
2	Other Revenue	(1)	$48,750	($21,109)	$27,641	$18,480	$46,121
3	Total Operating Revenues		$1,214,031	$19,906	$1,233,937	($19,342)	$1,214,596
	Operating Expenses:						
4	OM+A Expenses		$753,157	$16,738	$769,895	$ -	$769,895
5	Depreciation/Amortization		$180,507	$11,484	$191,991	($3,424)	$188,568
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$933,664	$28,222	$961,886	($3,424)	$958,463
10	Deemed Interest Expense		$95,669	($542)	$95,127	($2,119)	$93,008
11	Total Expenses (lines 9 to 10)		$1,029,333	$27,680	$1,057,013	($5,543)	$1,051,471
12	**Utility income before income taxes**		$184,698	($7,774)	$176,924	($13,799)	$163,125
13	Income taxes (grossed-up)		$19,099	($6,836)	$12,263	($10,131)	$2,132
14	**Utility net income**		$165,600	($938)	$164,661	($3,668)	$160,993

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$7,304	$395	$7,699	$ -	$7,699
	Late Payment Charges	$11,450	$ -	$11,450	$ -	$11,450
	Other Distribution Revenue	$21,996	($21,504)	$492	$18,480	$18,972
	Other Income and Deductions	$8,000	$ -	$8,000	$ -	$8,000
	Total Revenue Offsets	$48,750	($21,109)	$27,641	$18,480	$46,121

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Settlement Agreement
	Determination of Taxable Income			
1	Utility net income before taxes	$165,600	$164,661	$160,993
2	Adjustments required to arrive at taxable utility income	($28,152)	($76,408)	($145,647)
3	Taxable income	$137,448	$88,253	$15,346
	Calculation of Utility income Taxes			
4	Income taxes	$16,769	$10,767	$1,872
6	Total taxes	$16,769	$10,767	$1,872
7	Gross-up of Income Taxes	$2,330	$1,496	$260
8	Grossed-up Income Taxes	$19,099	$12,263	$2,132
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$19,099	$12,263	$2,132
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	9.00%	9.00%	9.00%
12	Provincial tax (%)	3.20%	3.20%	3.20%
13	Total tax rate (%)	12.20%	12.20%	12.20%

Notes

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$2,677,129	3.49%	$93,432
2	Short-term Debt	4.00%	$191,223	1.17%	$2,237
3	**Total Debt**	60.00%	$2,868,352	3.34%	$95,669
	Equity				
4	Common Equity	40.00%	$1,912,235	8.66%	$165,600
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$1,912,235	8.66%	$165,600
7	**Total**	100.00%	$4,780,587	5.47%	$261,269
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$2,661,958	3.49%	$92,902
2	Short-term Debt	4.00%	$190,140	1.17%	$2,225
3	**Total Debt**	60.00%	$2,852,098	3.34%	$95,127
	Equity				
4	Common Equity	40.00%	$1,901,399	8.66%	$164,661
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$1,901,399	8.66%	$164,661
7	**Total**	100.00%	$4,753,497	5.47%	$259,788
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$2,602,657	3.49%	$90,833
9	Short-term Debt	4.00%	$185,904	1.17%	$2,175
10	**Total Debt**	60.00%	$2,788,561	3.34%	$93,008
	Equity				
11	Common Equity	40.00%	$1,859,040	8.66%	$160,993
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$1,859,040	8.66%	$160,993
14	**Total**	100.00%	$4,647,601	5.47%	$254,001

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

		Initial Application		Interrogatory Responses		Settlement Agreement	
Line No.	**Particulars**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**
1	Revenue Deficiency from Below		($124,048)		($83,032)		($120,840)
2	Distribution Revenue	$1,289,329	$1,289,329	$1,289,329	$1,289,329	$1,289,315	$1,289,315
3	Other Operating Revenue Offsets - net	$48,750	$48,750	$27,641	$27,641	$46,121	$46,121
4	**Total Revenue**	$1,338,079	$1,214,031	$1,316,969	$1,233,937	$1,335,436	$1,214,596
5	Operating Expenses	$933,664	$933,664	$961,886	$961,886	$958,463	$958,463
6	Deemed Interest Expense	$95,669	$95,669	$95,127	$95,127	$93,008	$93,008
8	**Total Cost and Expenses**	$1,029,333	$1,029,333	$1,057,013	$1,057,013	$1,051,471	$1,051,471
9	**Utility Income Before Income Taxes**	$308,746	$184,698	$259,956	$176,924	$283,965	$163,125
10	Tax Adjustments to Accounting Income per 2013 PILs model	($28,152)	($28,152)	($76,408)	($76,408)	($145,647)	($145,647)
11	**Taxable Income**	$280,594	$156,546	$183,548	$100,516	$138,319	$17,478
12	Income Tax Rate	12.20%	12.20%	12.20%	12.20%	12.20%	12.20%
13	**Income Tax on Taxable Income**	$34,232	$19,099	$22,393	$12,263	$16,875	$2,132
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$274,513	$165,600	$237,563	$164,661	$267,091	$160,993
16	**Utility Rate Base**	$4,780,587	$4,780,587	$4,753,497	$4,753,497	$4,647,601	$4,647,601
17	Deemed Equity Portion of Rate Base	$1,912,235	$1,912,235	$1,901,399	$1,901,399	$1,859,040	$1,859,040
18	Income/(Equity Portion of Rate Base)	14.36%	8.66%	12.49%	8.66%	14.37%	8.66%
19	Target Return - Equity on Rate Base	8.66%	8.66%	8.66%	8.66%	8.66%	8.66%
20	Deficiency/Sufficiency in Return on Equity	5.70%	0.00%	3.83%	0.00%	5.71%	0.00%
21	Indicated Rate of Return	7.74%	5.47%	7.00%	5.47%	7.75%	5.47%
22	Requested Rate of Return on Rate Base	5.47%	5.47%	5.47%	5.47%	5.47%	5.47%
23	Deficiency/Sufficiency in Rate of Return	2.28%	0.00%	1.53%	0.00%	2.28%	0.00%
24	Target Return on Equity	$165,600	$165,600	$164,661	$164,661	$160,993	$160,993
25	Revenue Deficiency/(Sufficiency)	($108,914)	$ -	($72,902)	$0	($106,098)	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	($124,048) (1)		($83,032) (1)		($120,840) (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application	Interrogatory Responses	Settlement Agreement
1	OM&A Expenses	$753,157	$769,895	$769,895
2	Amortization/Depreciation	$180,507	$191,991	$188,568
3	Property Taxes	$ -		
5	Income Taxes (Grossed up)	$19,099	$12,263	$2,132
6	Other Expenses	$ -		
7	Return			
	Deemed Interest Expense	$95,669	$95,127	$93,008
	Return on Deemed Equity	$165,600	$164,661	$160,993
8	**Service Revenue Requirement (before Revenues)**	$1,214,031	$1,233,937	$1,214,596
9	Revenue Offsets	$48,750	$27,641	$46,121
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,165,281	$1,206,297	$1,168,475
11	Distribution revenue	$1,165,281	$1,206,297	$1,168,475
12	Other revenue	$48,750	$27,641	$46,121
13	**Total revenue**	$1,214,031	$1,233,937	$1,214,596
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ - (1)	$ - (1)	$ - (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Settlement Agreement	Δ% (2)
Service Revenue Requirement	$1,214,031	$1,233,937	**1.64%**	$1,214,596	**(100.00%)**
Grossed-Up Revenue Deficiency/(Sufficiency)	($124,048)	($83,032)	**(33.06%)**	($120,840)	**(100.00%)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,165,281	$1,206,297	**3.52%**	$1,168,475	**(100.00%)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	($124,048)	($83,032)	**(33.06%)**	($120,840)	**(100.00%)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Settlement Agreement

	Customer Class	**Initial Application**			**Interrogatory Responses**			**Settlement Agreement**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential	2,345	20,126,172	-	2,345	20,150,710	-	2,345	20,274,072	-
2	General Service < 50 kW	165	4,617,010	-	165	4,620,558	-	165	4,620,092	-
3	General Service > 50 to 4999 kW	9	3,952,566	11,414	9	3,960,295	11,414	9	3,959,895	11,413
4	Unmetered Scattered Load	17	93,084	-	17	88,338	-	17	88,338	-
5	Street Lighting	633	241,169	655	633	242,877	655	633	234,836	655
6	Micro Fit	-								
7	other									
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total	**3,168**	**29,030,001**	**12,069**		**29,062,778**	**12,069**		**29,177,234**	**12,068**

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Settlement Agreement***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	**Costs Allocated from Previous Studv** [1]	**%**	**Allocated Class Revenue Requirement** [1] (7A)	**%**
1	Residential	$ 687,249	77.36%	$ 995,711	81.98%
2	General Service < 50 kW	$ 107,690	12.12%	$ 123,205	10.14%
3	General Service > 50 to 4999 kW	$ 69,528	7.83%	$ 66,508	5.48%
4	Unmetered Scattered Load	$ 5,498	0.62%	$ 2,758	0.23%
5	Street Lighting	$ 18,461	2.08%	$ 26,414	2.17%
6	Micro Fit				
7	other				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 888,426	100.00%	**$ 1,214,596**	100.00%

Service Revenue Requirement (from Sheet 9) **$ 1,214,595.83**

---

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) *Calculated Class Revenues*

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 1,053,554	$ 954,810	$ 954,782	$ 38,435
2	General Service < 50 kW	$ 130,541	$ 118,306	$ 118,310	$ 5,117
3	General Service > 50 to 4999 kW	$ 67,337	$ 61,026	$ 63,225	$ 549
4	Unmetered Scattered Load	$ 5,919	$ 5,364	$ 3,190	$ 120
5	Street Lighting	$ 31,964	$ 28,968	$ 28,968	$ 1,900
6	Micro Fit				
7	other				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 1,289,315	$ 1,168,475	$ 1,168,475	$ 46,121

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2018 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	107.00%	99.75%	99.75%	85 - 115
2	General Service < 50 kW	88.00%	100.18%	100.18%	
3	General Service > 50 to 4999 kW	103.00%	92.58%	95.89%	
4	Unmetered Scattered Load	70.00%	198.84%	120.00%	
5	Street Lighting	70.00%	116.86%	116.86%	
6	Micro Fit				
7	other				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios (11)

	Name of Customer Class	**Proposed Revenue-to-Cost Ratio**			**Policy Range**
		Test Year	**Price Cap IR Period**		
			1	**2**	
1	Residential	99.75%	99.75%	99.75%	85 - 115
2	General Service < 50 kW	100.18%	100.18%	100.18%	
3	General Service > 50 to 4999 kW	95.89%	95.89%	95.89%	
4	Unmetered Scattered Load	120.00%	120.00%	120.00%	
5	Street Lighting	116.86%	116.86%	116.86%	
6	Micro Fit				
7	other				
8					
9					
10					
11					
12					
13					
14					
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16					
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(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: ***Settlement Agreement***

	Customer and Load Forecast					Class Allocated Revenues From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Fixed / Variable Splits [2] Percentage to be entered as a fraction between 0 and 1			Distribution Rates					Revenue Reconciliation		
	Customer Class From sheet 10. Load Forecast	**Volumetric Charge Determinant**	**Customers / Connections**	**kWh**	**kW or kVA**	**Total Class Revenue Requirement**	**Monthly Service Charge**	**Volumetric**	**Fixed**	**Variable**	**Transformer Ownership Allowance [1] ($)**	**Monthly Service Charge Rate**	**No. of decimals**	**Volumetric Rate Rate**		**No. of decimals**	**MSC Revenues**	**Volumetric revenues**	**Distribution Revenues less Transformer Ownership**
1	Residential	kWh	2,345	20,274,072	-	$ 954,782	$ 954,782	$ 0	100.00%	0.00%		$33.93	2	$0.0000	/kWh	4	$ 954,783.40	$ -	$ 954,783.40
2	General Service < 50 kW	kWh	165	4,620,092	-	$ 118,310	$ 40,009	$ 78,301	33.82%	66.18%		$20.25		$0.0169	/kWh		$ 40,015.38	$ 78,079.5578	$ 118,094.94
3	General Service > 50 to 4999 kW	kW	9	3,959,895	11,413	$ 63,225	$ 18,882	$ 44,342	29.87%	70.13%		$182.81		$3.8852	/kW		$ 18,882.39	$ 44,342.4601	$ 63,224.85
4	Unmetered Scattered Load	kWh	17	88,338	-	$ 3,190	$ 2,447	$ 742	76.73%	23.27%		$12.30		$0.0084	/kWh		$ 2,447.94	$ 742.0419	$ 3,189.98
5	Street Lighting	kW	633	234,836	655	$ 28,968	$ 16,254	$ 12,714	56.11%	43.89%		$2.14		$19.4100	/kW		$ 16,263.57	$ 12,713.5500	$ 28,977.12
6	Micro Fit		-	-	-												$ -	$ -	$ -
7	other		-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
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Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ 1,168,270.29
Base Revenue Requirement	$ 1,168,475.22
Difference	-$ 204.93
% Difference	-0.018%

Rates recover revenue requirement

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

[1] Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

[2] Short description of change, issue, etc.

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference [1]	**Item / Description [2]**	**Regulated Return on Capital**	**Regulated Rate of Return**	**Rate Base**	**Working Capital**	**Working Capital Allowance ($)**	**Amortization / Depreciation**	**Taxes/PILs**	**OM&A**	**Service Revenue Requirement**	**Other Revenues**	**Base Revenue Requirement**	**Grossed up Revenue Deficiency / Sufficiency**
	Original Application	$ 261,269	5.47%	$ 4,780,587	$ 4,046,164	$ 303,462	$ 180,507	$ 19,099	$ 753,157	$ 1,214,031	$ 48,750	$ 1,165,281	-$ 124,048
1													

D Summary of Accounting Guidance of accounts 1588/1589

1588 / 1589 Procedures Memo

For the purpose of this memo, please note that the CHEI does not receive IESO invoices. They are invoiced by Hydro One. For the OEB's reference, the charges CHEI incurs can be classified as follow (under OEB's charge types):

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

Key facts about the procedures:

- All data used throughout the process consists of actual data.
  - kWh billed to customers: Extracted from CHEI's billing cycle and readings, which are made available around the 8th of the following month and billed on the 17th (i.e., CHEI's readings for March usage are obtained by April 8th and are billed to the customers on April 17th)
  - Global adjustment: Obtained from Hydro One's invoice which is obtained around the 20th of the following month (i.e., Hydro One's invoice for March usage is obtained April 20th)
- The timeframe for the billing of CHEI also coincides with the Hydro One invoices (All from the 1st of the month to the last day of the month).
- Immediate procedures are performed by CHEI, such as Settlements and True-Ups, while BDO will review and reconcile the variances (1588/1589 and others) on a semi-annual basis. For BDO, the work is performed when all the information is made available for the analysis. As such:
  - January to June is performed by end of August
  - July to December is performed by end of March.

OEB – Q1 - The GA charge proportionally allocated to RPP and non-RPP customers is not calculated correctly. Cooperative Hydro Embrun has used total energy volumes rather than GA volumes (adjusted for embedded generation) on Hydro One Network Inc.'s invoice to determine the appropriate share of the GA charge allocated to each respective customer class, as required by the OEB's accounting guidance. In addition, the allocation percentage for the GA charges used by Cooperative Embrun appears to be not in accordance with the method to calculate the percentage in accounting guidance.

Cooperative Hydro Embrun is of the view that the GA volumes should exclude the MicroFit volumes, before the allocation into the RPP and Non-RPP portions. OEB staff is of the view that the GA volumes should include the MicroFit volumes into the allocation of the RPP and Non-RPP portions.

CHEI Response:

- CHEI does not obtain the breakdown of the Global adjustment from Hydro One. The only data available to allocate the GA charge consists of the kWh billed to customers.
- In order to response to the OEB's question, please refer to the procedures performed:

<u>Step 1: Determining the percentage of RPP customers and Non-RPP Customers.</u>

- On a monthly basis, CHEI extracts the kWh billed to RPP customers and non-RPP Customers. This amount agrees with the line "Electricity @ Spot Price" of the Hydro One's invoice.
- CHEI determines the percentage of kWh billed to RPP and non-RPP customers.
- CHEI then uses those percentages to allocate the GA volume (With embedded generation) between RPP and non-RPP customers.
- *Please note that the variation for the year 2021 between the total kWh billed to customers and the GA charge was 0.3106% (31,887,133 billed vs 31,986,491 GA)*

CHEI recognizes that the percentage allocation determined by CHEI does not include the embedded generation. However, the amount allocated between RPP and Non-RPP consists of the GA Volume with embedded generation. CHEI used this approach for the following reasons:

- The impact of the embedded generation volumes over RPP and Non-RPP established volumes would be trivial over the allocation percentage. (99,458 kWh of embedded generation over 31,887,133 kWh billed represents 0.3106%)
  - CHEI is using the hypothesis that the % of the Embedded generation would be similar to the billed RPP/non-RPP % (which is, in average, a ratio around 80%/20%). If that amount would differ it could impact the allocation, but CHEI believes this would be trivial when comparing to the extra fees they would need to incur on an ongoing basis in order to factor in the embedded generation.
    - For the year 2021, BDO performed "stress-test" scenarios in which embedded generation would be 100% RPP or 100% non-RPP. These scenarios resulted in:
      - 100% RPP : Increase of 0.05% to the RPP percentage.
      - 100% non-RPP : decrease of 0.3106% to the RPP percentage.
      - In other words, the allocation used by CHEI throughout the year could not differ, in the worst scenario possible, more than 0.3106%
- Since Embedded generation is on a different rate than the billed/purchased kWh, the calculations would increase the professional fees which would negate the potential positive effects for customers.

OEB – Q2 - The RPP portion of the GA claimed with Hydro One on the RPP settlement appears not to be calculated in accordance with the method required in the OEB's accounting guidance. As a result, the RPP portion of the GA charge may have resulted in a variance in Account 1588.

CHEI Response:

- Refer to Q1 for the Step 1 of the procedure process

Step 2: Calculation of the GA invoiced to RPP / non-RPP customers

  - CHEI uses the following calculations to determine the GA invoiced to RPP/ non-RPP Customers:

Global Adjustment per Hydro One Invoice
(less) Total True-up of Non-RPP *(As it's included in the Global adjustment above)*
Subtotal amount *(This subtotal agrees to the kWh invoiced by Hydro One * GA Actual rate)*
(Multiply) % of kWh billed to RPP customers
Subtotal amount *(This subtotal would represent "Charge Type 148 – RPP – 4705")*
(Plus/Minus) Bill 100 adjustment per Hydro One's subsequent invoice
Global Adjustment invoiced for RPP Customers

Global Adjustment per Hydro One Invoice
(Plus/Minus) Bill 100 adjustment per Hydro One's subsequent invoice
(Minus) Global Adjustment invoiced to RPP Customers
Global Adjustment invoiced for non-RPP Customers

Note for Step 2:
Bill 100 adjustments are calculated by CHEI on a monthly basis and submitted to Hydro One in order to include on the following month's invoice:

Grand total Usage of the month * Time-of-Use prices per kWh. This is performed by Off-Peak, Mid-Peak, On-Peak, Tier 1 and Tier 2
(Less) Grand Total Usage of the month * HOEP Power Price
(Less) Provincial benefit Power Bill (minus) Amount collected from Spot Customers
Bill 100 Adjustment

Bill 100 adjustments are shown on the Hydro One invoice 1 month after the month's billing since it requires CHEI to make their request to Hydro One. (So, January's Bill 100 adjustment is shown on the February's invoice which is received in March).

BDO's reconciliation procedures are performed 2 or 3 months after the period covered. By that time, it has all the actual data required, which includes the Bill 100 adjustments. BDO uses the Bill 100 adjustment shown on the February invoice for the month of January when performing the analysis.

Bill 100 adjustments are added to RPP Customers at 100% since the non-RPP customers of CHEI are not subject to such variances.

GA Invoiced for RPP Customers – OEB's method vs CHEI's.

- CHEI believes that the method used to determine the GA invoiced for RPP customers and non-RPP customers is in agreement with OEB's method.
    - CHEI established the same amount as determined at Table 14 of OEB's Illustrative Commodity Model ("Class B – GA Actual IESO Billed")
    - The allocation between RPP and Non-RPP is in agreement with Table 15 for the Charge Type 148.

Step 3: Calculation of the 1589 Variances

- 1589 variances are calculated based on the difference between the GA Invoiced for non-RPP customers and the GA billed to non-RPP customers
- GA Billed to non-RPP customers is easily identifiable as non-RPP customers are in distinct cycles.

1589 Variances – OEB's method vs CHEI's.

- Per OEB's tab of "Final RSVA Balances" – Table 41, there is two types of Variances, which are:
    - Price - Retail GA Price Billed vs Wholesale GA Actual Price paid to IESO
    - Volume - Retail vs Wholesale Volume Variance - (UFE differences)
- Since CHEI operates with the actual data, those difference would consist of:
    - Volume: Difference would stem from the Step 1 of CHEI's procedure but as noted would be minimal (Difference would be due to the embedded generation allocation).
    - Price: Difference stems from CHEI billing at 1st estimate, which total is established through the GA Billed to non-RPP Customers stated above, and Hydro One billing at actual rate, which total is established at Note 2.
        - To further evidence that the calculation is accurate, CHEI calculated that for the year 2021:
            - Calculated $ Consumption at actual rate paid (per CHEI model) = $332,082
            - $ Consumption at actual rate paid (per OEB's GA Analysis) = $330,570
            - The minimal difference of $1,512 was not investigated further as the work / fees needed to identify the driver of the variance would exceed the amount itself.

Step 4: Calculation of the GA billed for RPP Customers

Power Billed to Customers (On peak, off peak, mid peak, Tier-1, Tier 2 and Energy charge) – There is no non-RPP balances in these amounts.
(Minus) Commodity Purchase Hydro One (Account 470502), which is comprised of the Power bill amount from Hydro One (-) Bill 100 Adj. from the previous month (-) MicroFit.
(Plus) MicroFit - Included in 470502 (This is only to add back the amounts deducted from the Commodity Purchase Hydro One (Account 47502)
(Plus) Bill 100 Adj from the previous month - Included in 470502 (This is only to add back the amounts deducted from the Commodity Purchase Hydro One (Account 47502)

Global Adjustment billed to RPP Customers

In summary, the GA Adjustment Billed to RPP Customers consists of the Power Billed to Customers less the Power Bill from Hydro One, all of which relates to RPP customers.

GA billed to RPP Customers – OEB's method vs CHEI's.

- CHEI takes the total billed to RPP customers and removes the Power Bill amount (The electricity charge) from Hydro One's invoice as the amounts are factored in the Power billed to customers Price rates. By doing so, the remaining balance consists of the GA billed to Customers.

Step 5: Calculation of the 1588 Variances

  - 1588 variances are calculated based on the difference between the GA Invoiced for RPP customers and the GA billed to RPP customers

1588 Variances – OEB's method vs CHEI's.

- Per OEB's tab of "Final RSVA Balances" – Table 40, there is four types of Variances, which is
  - Class B – RPP – Price Variance: Retail vs Wholesale Price Variances
  - Class B – RPP – Volume Variance: Retail vs Wholesale Volume Variance - (UFE differences)
  - Class B – Non-RPP – Price Difference: Retail vs Wholesale Price Variances
  - Class B – Non-RPP – Volume Variance : Retail vs Wholesale Volume Variance - (UFE differences)
- Since CHEI operates with the actual data, those difference would consist of:
  - Class B – Non-RPP Price Difference: N/A – Per OEB's model, the Price difference stems from the Class a Non-RPP Revenue Rate minus the Class A Non-RPP Final Purchased price. CHEI does not have Class A customers.
  - Class B – Non-RPP Volume Variance: N/A – Per OEB's model, the Price cell to determine this variance stems from the Class A Non-RPP Revenue Rate.
  - Class B – RPP – Price Variance & Class B – RPP – Volume Variance: For CHEI's method, these variances are grouped together.
    - In general, the Volume are similar each month as the difference between kWh invoiced by Hydro One in GA and kWh billed to customers consists

  of the embedded generation (refer to explanations of Embedded generation in Question 1).
- As shown above, CHEI documented how the GA invoiced for RPP customers and GA billed to RPP customers calculated was in agreement with OEB's policies. The price variance consists of the difference between the two.

Final Verifications to ensure 1588/1589 calculations established are accurate:

- **CHEI also performs a verification of 1588 / 1589 variances.**
    - During the verification of the work, BDO will ensure that some Key aspects are in agreement.
    - 1st verification: Once adjustments for variances are made, BDO completes the GA Analysis Workform. This step is to ensure that the variances recorded agrees within 1% of the expected GA variance.
    - 2nd verification: At the end of the year, BDO will ensure that the total of the revenue accounts for the "Energy" will agree to the total of the expense accounts for the "Energy".

Following the explanations above, CHEI and BDO believes they have clarified the issues raised by OEB Staff with respect to CHEI's handling of accounts 1588 and 1589. It is our belief that, following OEB's guidance in 2020, CHEI and BDO have improved the process given the circumstances of CHEI's customer base and have been able to perform the analysis of 1588 / 1589 in a way that agrees with OEB's accounting guidance.

OEB – Q3 - Cooperative Embrun appears to not be accruing the RPP settlements for the last two months of the year and not reflecting the accruals in Account 1588. As a result, there is a misalignment and timing difference between the RPP settlements and the other commodity costs/revenues that are recorded on an accrual basis in Account 1588.

CHEI Response:

- For terms of simplicity for CHEI's accounting procedures, there is no unbilled revenue recorded throughout the year. The unbilled revenue is only recorded as of December 31st in order to ensure that all of the kWh used from January 1st to December 31st is recorded as a revenue and an expense over that same time period.
    - At the end of March, BDO will make an adjusting journal entry as of December 31st in order to record the unbilled revenue amount (which is based on the billing of December performed on January 17) and the accounts payable (which is based on the Hydro One invoice of January 20).
    - Following OEB's guidance in 2020, BDO also adds the bill 100 adjustments up to the February 17th invoice as it relates to the December usage.

- CHEI and BDO can confirm that the procedure above ensures that the variances accounts for all the kWh for the year.

OEB – Q4: Cooperative Hydro Embrun does not accrue unbilled revenue on a monthly basis, but it does perform an accrual at year-end.

CHEI Response:

- Refer to Q3 response for how the unbilled revenues are accrued.
- The Procedure for CHEI was performed this way as recording the unbilled revenue on a monthly basis did not provide additional useful information for CHEI and there is no reporting required to the OEB until the end of the year.