April 4, 2019
Ontario Energy Board P.O.
Box 2319 27th Floor
2300 Yonge Street Toronto,
Ontario M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary
Regarding: 2019 Cost of Service Application (EB-2018-0087)

Dear Ms. Walli,

Chapleau Public Utilities Corporation ("CPUC", "Chapleau Hydro") is pleased to submit to the Ontario Energy Board its response to the parties' interrogatories for its 2019 Cost of Service Application. These responses are being filed pursuant to the Board's e-Filing Services.

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

Alan Morin, General Manager
Chapleau PUC
110 Lorne Street South
P.O. Box 670
Chapleau, ON, P0M 1K0
Phone: 705-864-0111
Fax: 705-864-1962

Attention: Ms. Kirsten Walli, Board Secretary

Regarding: EB-2017-0035-2018 Cost of Service Application
Dear Ms. Walli,

Please find attached Cooperative Hydro Embrun Inc's responses to VECC and Board Staff' s interrogatories. This application is being filed pursuant to the Board's e-Filing Services.
We would be pleased to provide any further information or details that you may require relative to this application.
Yours truly,

Exhibit 1

1-Staff-1

Ref: Letters of Comment

Preamble:

OEB staff notes that CPUC has received one letter of comment to date regarding this proceeding. Section 2.1.7 of the Filing Requirements[1] states that distributors need to include all responses to matters raised in letters of comment filed with the OEB during the course of the proceeding, when available.

Question:

a) Please provide CPUC's response to the matters raised in the letter of comment that was filed by a customer on February 12, 2019.

b) Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Responses:

a) The letter provided to CPUC was a letter stating that the rate increase should be approved, and that the utility had provided sufficient rationale to support the increase. The letter states that the customer's questions were answered at the meeting and that the customer is satisfied with the service provided by the utility. Accordingly, it does not appear to CPUC that the letter requires a response.

[1] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service, July 12, 2018

b) CPUC commits to responding to any other letter of comments that arise throughout this proceeding.

1-Staff-2 Update Ch 2 append

Ref: All Exhibits and Models, for example Chapter 2 Appendices, Appendix 2-BA Chapter 2 Appendices, Appendix 2-AA

Preamble:

OEB staff notes that evidence contained in the exhibits and models contain forecasted 2018 data, instead of actual 2018 data.

Question:

a) With respect to all models and exhibits, please update the 2018 forecasted balances with actual 2018 balances, for example, Appendix 2-BA, Appendix 2-AA

Responses:

a) CPUC has updated all models with changes in rates and/or OEB policies which occurred after the filing date. CPUC has also updated the models to reflect corrections in the evidence. These models have been filed along with these responses.

1-Staff-3 Update RRWF

Ref: Updated RRWF

Question:

a) Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

Responses:

a) CPUC commits to updating the RRWF and all other relevant models with agreed-upon changes.

1-Staff-4

Ref: Exhibit 1, page 55

Preamble:

At the above-noted reference, CPUC stated the following:

> CPUC has had difficulties keeping its achieved ROE within the Board Approved ROE of 9.12. The main reason being that with total costs being so low and one-time costs being sometimes high, it is difficult for a small utility to keep within the range. That said, CPUC commits to using financial tools and checks to ensure the utility maintains its profitability at the approved level going forward.

Question:

a) Please describe in more detail the financial tools and checks CPUC plans to use to ensure the utility maintains its profitability at the approved level going forward.

Responses:
CPUC has created an MS Excel-based model which will help monitor and forecast the utility's financial performance. The design is rooted in its capability to enable better financial decisions and is intended to be used as a decision-making tool. The utility plans on using the model on a frequent basis to estimate the impact of capital projects and OM&A expenses on financial statements and ROE.

1-Staff-5

Ref: Exhibit 1, page 106

Preamble:

At the above-noted reference, CPUC stated the following:

> CPUC admits that until this Cost of Service, it had taken a passive more reactive approach to customer service but that in preparing the application, CPUC was reminded of the value of the Renewed Regulatory Framework for Electricity which contemplates enhanced engagement between distributors and their customers to better align a distributor's operational plans with its customers' needs and expectations.

Question:

a) Please explain why CPUC took a more passive and reactive approach to customer service in the past.

Responses:
The excerpt should have stated that in the past, the utility had taken a passive, more reactive approach to customer "engagement" as opposed to customer "service." Customer service along with "keeping the lights on" have always been a top priority for CPUC.

1-Staff-6

Ref: Exhibit 1, pages 118 to 123

Preamble:

CPUC did not provide a complete 2017 scorecard in its evidence. CPUC did not include a discussion of its performance for each of the distributor's scorecard measures over the last five years. CPUC provided information for the past four years (2013 to 2016) at the above-noted reference.

Questions:

a) Please provide the complete 2017 scorecard.

b) Please provide a discussion of its performance for each of CPUC's scorecard measures and the trend and performance over the last five years.

Responses:
Preamble: Staff is correct in that CPUC did not file a 2017 scorecard as part of the application. CPUC feels it important to bring up the timelines between the release of the scorecard and the filing deadline for 2019 Cost of Service applications and the reasonableness of Staff's expectations. CPUC notes that a Cost of Service is a sizeable document which generally requires several days of production especially for a small utility which relies heavily on 3 party services such as consulting and outside printing firms. CPUC notes that the OEB released revised scorecard data on August 27, 2018, 5 business days before the cost of service filing deadline. CPUC feels that it is unreasonable to expect a utility whose resources are limited to make changes to an application that is already in production a mere 5 days before the filing deadline.

a) The 2017 scorecard can be found on the next page.

b) See section following the scorecard

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		100.00%	100.00%	100.00%	100.00%	99.68%		65.00%	
	Customer Satisfaction	First Contact Resolution			100%	100	100	100			
		Billing Accuracy			100.00%	99.99%	99.99%	99.99%		98.00%	
		Customer Satisfaction Survey Results			95%	95	95	95			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness				76.00%	76.00%	79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	NI	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.18	0.28	4.75	1.82	0.94			1.36
		Average Number of Times that Power to a Customer is Interrupted [2]		2.58	0.38	1.07	0.63	0.69			0.92
	Asset Management	Distribution System Plan Implementation Progress			0%	50	100	75			
	Cost Control	Efficiency Assessment		4	4	4	4	4			
		Total Cost per Customer [3]		$653	$729	$735	$740	$718			
		Total Cost per Km of Line [3]		$30,175	$33,329	$33,436	$34,163	$29,706			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]				26.22%	44.81%	66.56%			1.05 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.75	2.04	2.05	2.03	1.95			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.00	0.00	0.00	0.00	0.00			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
			Achieved	19.84%	16.88%	0.40%	-3.82%	-1.99%			

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

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

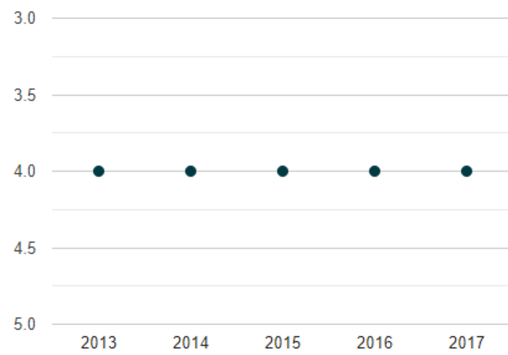
Scorecard Results and Analysis

COST CONTROL

Efficiency rating

4 (2017)

The utility must manage its costs successfully in order to help assure its customers they are receiving value for the cost of the service they receive. Utilities' total costs are evaluated to produce a single efficiency ranking. This is divided into five groups based on how big the difference is between each utility's actual and predicted costs. Distributors whose actual costs are lower than their predicted costs are considered more efficient.



1 = Actual costs are 25% or more below predicted costs

2 = Actual costs are 10% to 25% below predicted costs

3 = Actual costs are within +/- 10% of predicted costs

4 = Actual costs are 10% to 25% above predicted costs

5 = Actual costs are 25% or more above predicted costs

1.1.1 SERVICE QUALITY

From the period of 2013-2017, the utility ‘s results were recorded as 100% on all its Service Quality measures with the exception of Telephone Calls answered on time in 2017 (99.68%) where 1 call was not answered on time. Despite its perfect results, the utility along with neighbouring utilities has put a new process in place. CPUC expects that over time its results should remain strong.

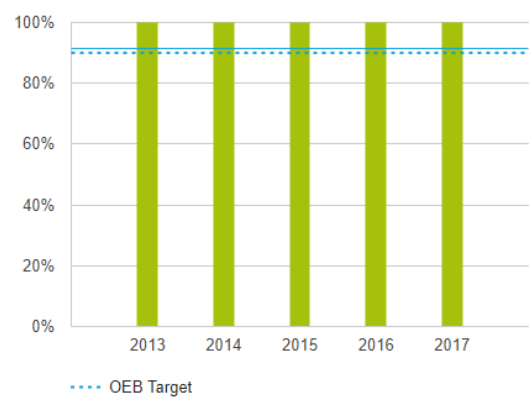
SERVICE QUALITY

New residential/small business services connected on time

100% (2017)

The utility must connect new service for the customer within five business days, 90 % of the time, unless the customer agrees to a later date. This timeline depends on the customer meeting specific requirements ahead of time (such as no electrical safety concerns in the building, customer's payment information complete, etc.)

✔ Target met



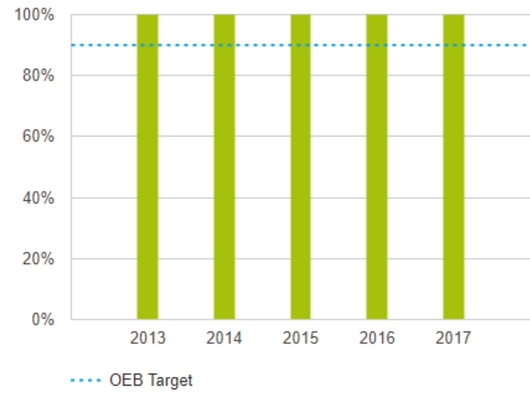
SERVICE QUALITY

Scheduled appointments met on time

100% (2017)

For appointments during the utility's regular business hours, the utility must offer a window of time that is not more than four hours long, and must arrive within that window, 90 % of the time.

Target met



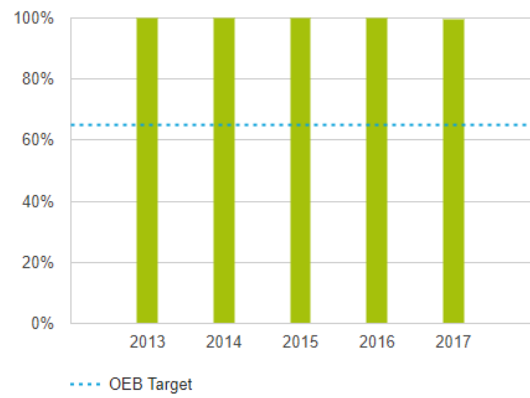
SERVICE QUALITY

Telephone calls answered on time

99.68% (2017)

During regular call centre hours, the utility's call centre staff must answer within 30 seconds of receiving the call directly or having the call transferred to them, 65 % of the time

Target met



1.1.2 CUSTOMER SATISFACTION

CPUC conducted its bi-annual customer satisfaction survey in Spring 2015 and then again in the spring of 2017 in advance of the Cost of Service. The results are presented in Section 1.8 of this Exhibit. Customers are generally satisfied with CPUC as reported in the Customer Satisfaction Survey (not yet reported on the Scorecards), which show a satisfaction rate of 95%. While CPUC manages less than 15% of the total customer bill, it continues its efforts to maintain appropriate cost control while providing safe and reliable delivery of power to its customers. First Contact resolution has remained high over the period of 2014-2015 as has the Billing Accuracy with results of 99.99% in 2015 2016 and 2017.

CUSTOMER SATISFACTION

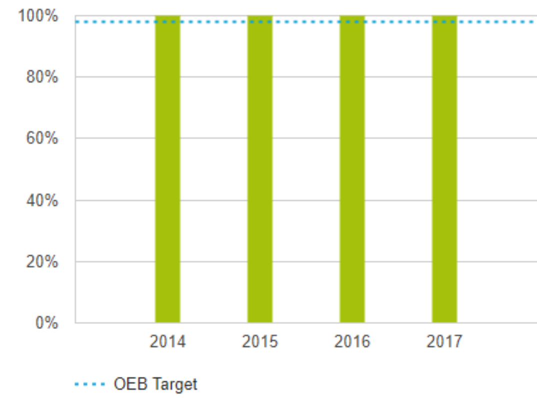
Billing accuracy

99.99% (2017)

An important part of business is ensuring that customer's bills are accurate. The utility must report on its success at issuing accurate bills to its customers.

More information about billing accuracy

Target met



CUSTOMER SATISFACTION

Complaints

0.00 (2017)

This metric measures the number of complaints the Ontario Energy Board received from customers about matters within our authority. Complaints made directly to the utility are not reported here. We measure this per 1000 customers so utilities that serve much larger or smaller populations can be compared against each other.

Year	Complaints per 1000 customers	Total number of complaints
2013	0.00	0
2014	0.00	0
2015	0.00	0
2016	0.80	1
2017	0.00	0

1.1.3 SAFETY

Safety remains a core attribute of CPUC's as it delivers power to its employees and customers daily. CPUC continues to strive to communicate on safety throughout our distribution system through various methods including safety orientations, online, outreach, and telephone. Results over the past 5 years show no Serious Electrical Incident Index.

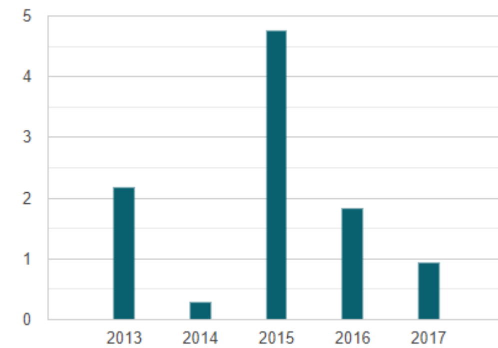
1.1.4 SYSTEM RELIABILITY

The reliability of the system remains a cornerstone of CPUC with attention distribution system infrastructure. Most interruptions continue to be because of supplier losses.

SYSTEM RELIABILITY

Average number of hours power to a customer was interrupted
0.938312h (2017)

An important feature of a reliable distribution system is recovering from power outages as quickly as possible. The utility must track the average length of time, in hours, that its customers have experienced a power outage over the past year.

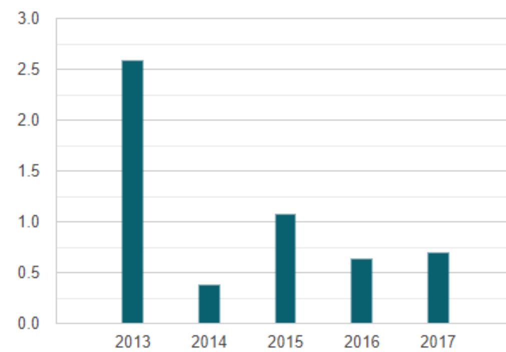


SYSTEM RELIABILITY

Average number of times power to a customer was interrupted
0.690501 (2017)

Another important feature of a reliable distribution system is reducing the frequency of power outages. Utilities must also track the number of times their customers experienced a power outage during the past year.

More information about interruption frequency



1.1.5 ASSET MANAGEMENT

The Distribution System Plan detailing the utility's historical and projected capital plan can be found in Exhibit 2 of this application.

1.1.6 COST CONTROL

From 2013 to 2017, CPUC has remained in the efficiency group 4. Despite having lower than average efficiency rating, CPUC continues to strive to achieve greater efficiency through productivity improvements and cost control, without compromising safety and reliability.

COST CONTROL

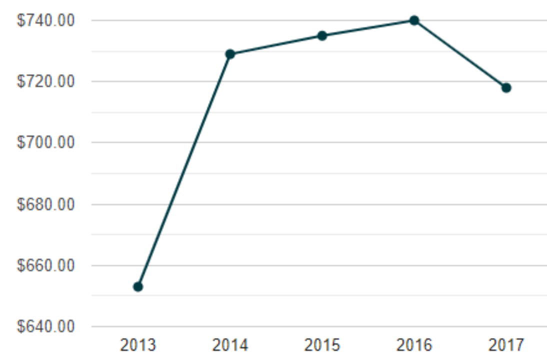
Cost per customer

$718 (2017)

A simple measure that can be used as a comparison with other utilities is the utility's total cost per customer.

Total cost is a sum of all the costs incurred by the utility to provide service to its customers. The amount is then divided by the utility's total number of customers. This amount does not represent how much customers pay for their utility services.

More information about Cost per Customer



1-Staff-7

Ref: Exhibit 1, page 263

Preamble:

At the above-noted reference, CPUC stated the following regarding changes in Other Revenue:

> [There is a] reduction in revenue offsets related to Hydro One's reducing CPUCs service to 911 emergencies only.

Question:

a) Please quantify the impact on the 2019 test year revenue requirement from the above-noted reductions in revenue offsets.

Responses:

a) See table below

HYDRO ONE INVOICING HISTORY

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work		1,048.00	284.07	465.55	722.73	715.01		13,985.19		
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	1,685.25					400.00		678.38		
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	344.47			182.56		220.00	290.00	870.72		
Rural Work				94.69						
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	2,446.83	522.15	896.35	824.55	491.49		2,107.62	999.14	1,150.00	865.00
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	1,222.84	1,828.53	491.49	1,546.98		585.41	593.22	896.48	270.00	
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	4,468.30	862.57	304.81	1,663.69	3,590.60	350.00	470.74	1,796.32	1,395.00	368.73
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	360.33		2,541.75	2,408.56	258.23	1,735.45	1,688.81	1,806.10		4,827.40
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	2,709.06	1,648.86	533.12		94.69	1,083.97	2,370.13	710.00		
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	1,785.00	1,014.07		4,001.41	783.36	222.50	1,406.19	710.00	2,260.00	
Rural Work	172.64									
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00	1,180.00					
Rural Work	1,485.39	612.43	506.82	1,469.31		5,090.13	2,917.84			
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00						
Rural Work	2,530.48	1,544.99	1,764.84	1,051.91	910.00	2,733.11	1,340.96	539.00	832.62	470.00
Admin and Storage	1,180.00	1,180.00	1,180.00	1,180.00						
Rural Work	1,675.77	513.13	2,829.08	450.83	669.82		1,357.50	165.00		
Joint Use (PUC)	429.15	600.81	600.81	600.81	600.81	600.81	600.81	600.81	600.81	600.81
Sale of assets (PUC)									2,016.00	
	35,475.51	24,355.54	24,913.14	28,920.85	19,921.73	13,736.39	15,143.82	23,757.14	8,524.43	7,131.94

1.0-VECC-1

Reference: Exhibit 1, pg. 20

a) Please provide the reasons CPUC's productivity is declining from stretch factor cohort 4 to 5.
b) CPUC is among the least efficient electricity distribution utilities in the Province as measured by the OEB sponsored PEG Benchmarking studies. What specific steps is the Utility taking to improve its productivity?

Responses:

a) The primary reason for the decline in the stretch factor is the addition of the assets from the affiliate to the utility. If the highlighted input below was set to 2017 levels, the stretch factor would have remained at 4.

	2014	2015	2016	2017	2018	2019
	(History)	**(History)**	**(History)**	**(History)**		
Cost Benchmarking Summary						
Actual Total Cost	899,874	902,761	922,404	888,710	1,021,402	1,028,300
Predicted Total Cost	682,181	711,003	747,552	757,964	767,637	777,981
Difference	217,693	191,758	174,852	130,746	253,765	250,318
Percentage Difference (Cost Performance)	27.70%	23.88%	21.02%	15.9%	28.6%	27.90%
Stretch Factor Cohort - Annual Result	4	4	4	4	5	5

Actual Cost		**2016**	**2017**	**2018**	**2019**
OM&A		735,273.37	705,401.32	792,904.00	804,473.00
Capital					
	Rate of Return	6.28%	6.28%	6.28%	6.02%
	Depreciation Rate	4.59%	4.59%	4.59%	4.59%
	Construction Cost Index	165.10	167.11	169.14	171.20
	Capital Price	17.83	18.05	18.27	18.04
	Gross Plant Additions	36,284	24,057	476,662	80,667
	HV Capital Additions	-	-	-	-
	The quantity of Capital Additions	220	144	2,818	471
	The quantity of Capital Removed	494	482	466	574
	Capital Quantity	10,496	10,158	12,510	12,407
	Capital Cost	187,131	183,309	228,498	223,827
Total Actual Cost		922,404	888,710	1,021,402	1,028,300

b) CPUC will continue to find efficiencies in its variable costs where ever possible. That said, the parties need to understand that there is a minimum cost of running a utility regardless of how many customers this utility has. For a utility to be functional, it needs no less than 3 employees in its offices. Any smaller number of employees makes day to day operations difficult as CPUC is realizing now that one of its employees has taken ill and will be off for an indefinite period of time. CPUC also does not have the ability to outsource its operational work; closest contractor is 2 hour drive at the minimum depending on weather and time of year, not to mention road closures. Therefore, for safety purposes; it requires a minimum of 2 linemen to be operational. CPUC will continue to look for opportunities to offset its revenue requirement by finding additional work for the linesmen, however, being in a small town, the potential for revenue offsets is limited.

Taking all of this in consideration, CPUC would like to see its efficiency improve and will continue to work with neighbouring utilities and other small utilities to find ways to reduce costs and be more efficient.

1.0-VECC-2 file supplier list

Reference: Exhibit 1, pg.70

a) Please provide an updated Table 35 (Supplier List) for 2018.
b) What services does ‘Tim Sinclair Consulting’ provide to Chapleau?

Responses:

a) The supplier list is being filed along with these responses.

b) Tim Sinclair Consulting provides CPUC with IT support and billing software.

Exhibit 2

2-Staff-8

Ref: Appendices FA Continuity Schedules

Preamble:

The evidence is unclear in the instances noted below.

Questions:

a) For 2018, it appears that additional columns added for “transfer of assets” have not been included in the calculation of net PP&E. Please review the instructions and accounting guidance and provide justification for not including them.

b) Please explain amounts recorded in the “transfer of assets” columns, and why they are not considered additions /disposals.

c) Please update the evidence as needed.

Responses: a), b), c)
CPUC disagrees with Board Staff. Exhibit 2 pages 32 and 33 clearly show the gross and net book value increase by approximately 500K from 2017 to 2018. Furthermore, the Excel workbook called “CPUC 2019 FA and Depreciation Cont. Schedule 20180831” filed on August 31, 2018, clearly shows the addition of the transfer of assets at line F430 to F480 (MIFRS) and at Y430 to Y480 (CGAAP).

2-Staff-9

Ref: Appendices FA Continuity Schedules, Appendix 2-C, Appendix 2-BA

Preamble:

There are material differences between depreciation expense per Appendices 2-Cs and FA Continuity Schedules. CPUC has not explained the differences, as required per Note 6 at the bottom of Appendix 2-C. Note 6 states: “The applicant must provide an explanation of material variances in evidence. Below are the differences noted (all are from MIFRS schedules):

	2-BA	2-C	Difference
2019	120,706	58,168	62,538
2018	159,505	44,574	114,931
2017	49,114	33,777	15,337
2016	52,874	114,068	(61,194)
2015	50,827	85,747	(34,920)
2014	72,466	90,948	(18,482)

Question:

a) Please provide an explanation for the variances.

Responses:
The reason for the discrepancy was provided at Section 4.8.2 of Exhibit 4.
“CPUC notes that its accounting firm/auditors use a declining balance method of calculating its depreciation. This has been always been the case. CPUC notes that under the previous management, and based on the asset base at the time of transition, the amortization method suggested by KPMG that best represented the pattern of usage of the assets was declining balance as the assets were deemed to be most useful when they were first purchased, providing the greatest potential at that point. In a recent discussion with KPMG, the firm stated that under the IFRS rules, the useful lives and method of amortization is required to be assessed on an annual basis. For the 2018-year end, it was determined in order to be consistent with the sector the method of amortization changed to the straight-line method, with the useful lives changing where necessary to be consistent with the Kinetics report. In addition, the useful lives of assets transferred over to CPUC from CESC (affiliate) were changed to ensure the useful lives were consistent for each asset which was similar in nature.”
Continuity Statements of the historical and forecasted depreciation expenses are presented are filed in Excel format along with this application.

2-Staff-10

Ref: Exhibit 2, Page 96

Preamble:

At the above-noted reference, CPUC stated the following with respect to its O&M and capital investments:

> With an increasing aging distribution system and the requirements to obtain asset condition assessments, the O&M cost metrics will remain steady whereas the increased renewal investment would increase the capital cost metrics…

Questions:

a) Please describe in more detail how the trade-offs made between CPUC's proposed level of capital expenditures with the proposed level of operating costs have been given adequate consideration, in particular regarding both budgeted costs and ad-hoc costs.

b) Please identify any initiatives considered and/or undertaken by CPUC, including any analysis conducted, to optimize plans and activities from a cost perspective, including balancing cost levels of OM&A versus capital.

Responses:

a) An example of when CPUC considered the trade-offs between capital and O&M costs is by performing oil reclamation on its station transformers to extend their useful life rather than investing in capital to renew the transformers, which would be significantly more expensive.

CPUC's proposed level of expenditures for the DSP forecast period largely targets the renewal of distribution wood poles. The proposed level of Capital expenditures is projected to increase as CPUC starts to work towards having feeders ready for voltage conversion in 2023 within. O&M expenditures are the minimum amounts required for CPUC to comply with the DSC and maintaining its assets at the expected inspection/maintenance cycle. The O&M expenditures are required to keep the operating system at the current safety, service and reliability performance. Therefore, CPUC cannot usually trade-off reduced O&M spending for increased capital spending. Likewise, increasing the forecast capital expenditure slightly in comparison to OEB's previous decision allows for CPUC to maintain its asset base by replacing assets before they reach critical condition. It is important to note that CPUC has limited resources such that should an increased number of assets experience failure. CPUC will not easily be able to address all assets simultaneously and swiftly; accordingly, it is critical that CPUC do what it can to minimize the likelihood of asset failure by replacing assets in a timely manner.

b) As described above, the O&M expenditures represent the bare minimum for CPUC to address its assets and to follow the DSC without receiving a penalty.

An activity that CPUC does do to reduce capital costs is reusing in-service transformers. In other words, when a pole is being replaced, and a transformer is on said pole, the transformer's condition is evaluated. Should said transformer be in good condition, it is relocated onto a different pole either within the same circuit, another circuit or stored for emergency use. This allows for CPUC to keep capital costs lower.

2-Staff-11

Ref: Exhibit 2, Section 2.5.2, Distribution System Plan, Page 57, Section 4 Capital Expenditure Plan (5.4)

Preamble:

At the above-noted reference, CPUC stated the following:

> This section describes CPUC's five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of CPUC's capital expenditure planning process, an assessment of CPUC's system to connect new REG, a summary of capital expenditures, and justification of capital expenditures.

Questions:

a) Please confirm that CPUC uses the term "capital addition" interchangeably with the term "capital expenditure" throughout the evidence. If this is not the case, please explain.

b) Please confirm that when the term "capital expenditures" is used, CPUC has presented all information on the basis of capital additions and has not included work in process in its numbers. If this is not the case, please explain and indicate areas of the evidence that are impacted.

Responses:

a) "Capital addition" is used once within the DSP and holds the same definition as "capital expenditure".

b) Confirmed.

2-Staff-12

Ref: Excel Appendix 2-AB, November 26, 2018
2012 Cost of Service Decision and Order, November 29, 2012, page 8 & 9[2]

Preamble:

The average of CPUC's actual annual capital expenditures from 2012 to 2017 is about 116%, or approximately $68,000, greater than the 2012 OEB-approved amount of $58,290, which is shown at the above noted second reference. A large part of this increase is due to the implementation of smart meters in 2012.

Questions:

a) In its annual capital planning and implementation for the years, 2012 to 2019 did the applicant take into account the cumulative impact its capital expenditures would have on rates in 2019?

b) What changes ensued from these considerations?

c) Please explain how CPUC's average actual historical capital spending from 2012 to 2017 of approximately $126,000 has been adequate to meet the needs of its customers, in particular, maintaining service reliability and service quality standards.

Responses:

a) Where CPUC can possibly foresee and identify costs, CPUC strives to keep cost impacts and rates experienced by customers to a minimum. In 2012, CPUC invested in a large capital expenditure due to the transfer of smart meter accounts. As a result, CPUC, in the following years, was stringent with its capital expenditures to offset the high expenditure incurred in 2012. In 2015, CPUC commissioned a customer engagement survey. As this was a new requirement imposed by the OEB on CPUC, the cost was unforeseen. However, CPUC in the following years was prudent with its capital expenditures. Removing these large investments from the analysis, the average actual annual capital expenditures from 2012 to 2017 is about 25%, or approximately $14,700, less than the OEB-approved amount of $58,290.

b) In light of the large investments, CPUC made adjustments to manage the expenditures were made to the asset renewal program activities with

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deferral of activities where appropriate. CPUC managed its renewal investments prudently by only investing in what was critical to replace to maintain safety to the public and CPUC crews while keeping the environment safe and maintaining reliable service for its customers.

c) The significant capital expenditure in 2012 consisting of transferring smart meter accounts to a new data management tool. The investment was required in order to transition customer billing biannually to monthly to alleviate the bill shock customers experienced and to inform customers of the important announcement on a more often reoccurring basis. In 2015, CPUC commissioned a Customer Engagement study to fulfill the OEB requirement when developing the DSP. Furthermore, CPUC began collecting data for a digitized GIS database. There is an increasing trend with LDC's moving towards digitization of records as there are added efficiency benefits to be gained from versus the traditional paper-based records. Removing these large investments leaves CPUC investing prudently in its system to maintain service quality and reliability while maintaining cost impacts low.

As explained in 2-Staff-12a, the average actual annual capital expenditures from 2012 to 2017 is about 25%, or approximately $14,700, less than the OEB-approved amount $58,290 when not considering the large one-time investments into the analysis.

2-Staff-13

Ref: Exhibit 2, Distribution System Plan, page 8

Preamble:

At the above noted reference, CPUC stated the following:

> The system O&M costs budgeted over the forecast period are, on average, 7.7% higher than the historical period costs. The main drivers for the increase in system O&M costs over the forecast period are:
>
> - Increased O&M costs associated with IT systems; and
> - Distribution system inspection cost increases to acquire condition data on assets.

Questions:

a) Please provide CPUC's calculations underpinning the 7.7% increase in O&M costs.

b) Please provide more detail regarding the increased O&M costs associated with IT systems, as well as the inspection costs.

Responses:

a) Referencing 2-Staff-31, the O&M costs have been revised and provided in the updated table. CPUC notes an error was made when costs were compiled into the tables.

b) As noted in part (a), there are no increased costs. O&M costs associated with IT systems involve maintaining the existing databases as well as expending the databases as additional data is being collected.

Furthermore, CPUC revisited its urgency in collecting nameplate and conditional data on its assets. CPUC has integrated the data collection process within its current inspection cycle. This results in no increase of O&M and grants CPUC operational efficiency. Additionally, CPUC follows the DSC for minimal inspection cycles of assets as another avenue for maintaining O&M costs at current levels.

2-Staff-14

Ref: Exhibit 2, page 71 of 221,[Distribution System Plan – 2019-2023, page 8]

Preamble:

The Distribution System Plan provides an outline of the option for voltage conversion, potentially over a 10-15 year period. The DSP notes:

> CPUC is following a recommended option after a completed line loss assessment. The option is to expend $20-100k on transformer testing and rehabilitation, with the objective of delaying the station replacement 5-10 years. In the meantime, increasing the pole replacement renewal as much as practical for 5-7 years, to establish one or two feeders ready for voltage conversion (allowing for voltage converters), then replacing transformers as needed, and converting the rest of the poles might allow for the $2Million conversion costs to be spread over 10-15 years. The primary risks would be the potential for a transformer to fail early, or for poles to start to fail quickly, both of which can be managed with increased monitoring and risk assessment. This plan will allow for a staging of capital costs, and a parallel improvement in cost of losses which would commence once the voltage conversion begins.

Questions:

a) The exact sequencing of work in the voltage conversion program is unclear. Can CPUC provide a more detailed description of the steps to be taken in the voltage conversion program and of the scheduling of these steps over time?

b) What is the basis of the estimate of $2 M for the conversion program? Please provide supporting details.

c) A projected expenditure of $2M over 10 to 15 years would yield an average annual capital spend of at least $133k per year. Given the request to spend $80.7k per year between 2019 – 2023, what is the anticipated capital expenditure profile beyond 2023?

d) Are any additional costs incurred as a result of the spreading of the conversion program over time? (For example as a result of investment in interim assets, such as line transformers suitable for the existing delivery voltage, that will then need to be replaced after a short period of time.) If so, what additional costs are expected?

e) What is the expected dollar value of the reduction in lines losses that will occur with full voltage conversion?

f) At what point in the voltage conversion program will the benefits of line loss reductions be achieved?

g) In the event that one of the two existing DS transformers fails early, what are the implications for conversion tasks, costs, and scheduling?

h) What rehabilitation will be undertaken on transformers (i.e. what is the planned remediation that falls within the $20-100k testing and rehabilitation budget noted)?

i) When is the rehabilitation that is noted in Question (h) expected to be scheduled? Is this included in the proposed capital spending program for 2019-2023?

j) Noting the four alternatives outlined in Appendix D (pages 191-192) of Exhibit 2 differ from the two alternatives proposed in the DSP (pages 130 – 131), what is the financial cost/benefit comparison of these various alternatives in comparison to the proposed program?

Responses:

a) CPUC provides the below table with the tentative planning years and activities that relate to voltage conversion:

Tentative Planning Year	Activity
2026	T3 Station Transformer Renewal
2026	20% of feeder F2 to be converted to 25kV
2028	The remainder of feeder F2 to be converted to 25kV
2031	T4 Station Transformer Renewal
2031	20% of feeder F9 to be converted to 25kV
2032	The remainder of feeder F9 to be converted to 25kV
2035	50% of feeder F8 to be converted to 25kV
2036	The remainder of feeder F8 to be converted to 25kV

Notes:

- Transformer voltage converters will be used to assist with converting the feeders
- Poles that need to be renewed will be replaced meeting the standard for 25kV network
- Transformers and cables to be replaced to meet 25kV network standards

b) The $2M estimate consists of pole replacement to meet the current standards for use in a 25kV system, upgrading distribution transformers and installation of new overhead conductors for a 25kV system. 50% of the estimate would be for replacing poles without the use of contractors, whereas the remaining 50% would be for upgrading transformers and overhead conductors. The $2M estimate does not capture the cost of the transformers which would be an additional $1.5M, nor the cost of the use of external contractors to complete the work.

c) CPUC's attempt to estimate the projected expenditures per year for the voltage conversion is shown below. The costs also include an estimate for the use of contractors to replace a set of poles per year.

Year	Estimate Expenditure
2024	$ 115,333
2025	$ 115,333
2026	$ 896,859
2027	$ 241,437
2028	$ 115,333
2029	$ 127,000
2030	$ 127,000
2031	$ 987,737
2032	$ 569,948
2033	$ 127,000
2034	$ 138,667
2035	$ 233,135

2036	$ 233,135
2037	$ 138,667
2038	$ 138,667

There may be additional costs related to spreading the voltage conversion over time such as premature failure of the existing assets, however, CPUC believes that spreading the costs over time will help to the cost increases to be incurred by the customers as a result of the voltage conversion program if it were to be completed within a short period of time. Hence, CPUC is planning to minimize the impact of a long-term conversion program, e.g., by utilizing voltage converters for existing transformers in service.

d) The expected savings as a result of a full voltage conversion is estimated to be approximately $119,900/year. This dollar value is strictly the savings from the line loss.

e) The benefits of line loss will be achieved upon converting all feeders to the 25kV system. The tentative planning year at this time is 2036.

f) Should a transformer fail earlier, CPUC would first investigate the failure and attempt to remediate the issue. This includes correcting the defect so that the transformer can continue to be in service. If the transformer cannot be salvaged, CPUC would investigate installing the new 25kV transformer and utilize transformer voltage converters to deliver the appropriate service level to its customers.

g) The planned rehabilitation for both transformers was oil reclamation which was completed in October 2018. The cost was $23,500.

h) The planned rehabilitation for both transformers was oil reclamation which was completed in October 2018. It is not part of the proposed capital spending program for 2019-2023.

i) The table below presents the financial cost/benefit between the four options presented in Appendix D. The cost of each project is over the time period 2024-2038 (15-year period). Additionally, the total cost of each option does not consider the cost of contractors, however, it is assumed the use of contractors would be the same for each option.

j)

	Option 1	Option 2	Option 3	Option 4
Total Cost	$ 1,618,000	$ 1,830,000	$ 2,490,000	$ 868,000
Benefit Cost	-$ 2,877,217	-$ 2,877,217	-$ 1,580,263	-$ 3,877,217
Savings compared to Option 4	$ 1,000,000	$ 1,000,000	$ 2,296,953	-

2-Staff-15

Ref: Exhibit 2, page 186 of 221, [METSCO Report, page 8]. Also, Table 1, page 181 of 221

Preamble:

The METSCO report notes the following with respect to transformer health:

> "Transformer T4 is showing signs of degradation and is in a condition much worse than expected for a transformed [*sic*] that is <20 years old. This transformer should be tested regularly, and a plan put in place for replacement most likely in the next 5-10 years. Transformer T3, is showing some indication of moisture ingress and should also be monitored closely.
> As a minimum, comprehensive condition testing is recommended for T4 and T3 which may lead to a rehabilitation plan."

Questions:

a) In the proposed voltage conversion program, when are Transformers T3 and T4 expected to be replaced?

b) Based on Table 1, it appears that loading on T3 is much less than on T4. Given the deteriorated condition of T4, has CPUC analyzed the potential to switch load from one transformer to the other or, alternatively, to swap the positions of these transformers, in order to reduce loads on T4 and increase its expected service life? If so, please provide the results of any analysis that was done.

c) Has the recommended condition testing occurred? If so, what were the results of this analysis? If testing has not occurred, has the condition testing been scheduled?

Responses:

a) See 2-Staff-14.

b) Post-filing CPUC's application, CPUC presented to its Board of Directors three immediate options to the station loading:

i. Do nothing and continue operating at current transformer loads with the risk of overloading present on T4.
ii. Off-load part of F9 feeder to F2 which will reduce the total load on station T4.
iii. Perform additional maintenance activities at a cost and an analysis on switching or transferring loads between transformers.

The selected option was (ii) since no additional costs would be incurred by CPUC and would result in an immediate decrease in load of station transformer T4. To date, the load switch stands and CPUC is monitoring the transformers.

c) The recommended oil reclamation was completed in October 2018 successfully on both T3 and T4. Additionally, rubber seals and valves were replaced where water ingress was identified. CPUC plans to conduct its normal station maintenance activities in Spring 2019 which includes oil sampling (oil quality and DGA), IR scans and visual inspections. The oil sampling will inform CPUC of the current state of the transformers post-oil refurbishment.

2-Staff-16

Ref: Exhibit 2, pages 72 and 175 of 221, [Distribution System Plan – 2019-2023, pages 9 and 90].

Preamble:

The DSP claims the following on page 9:

> Based on past customer interactions and surveys, CPUC has concluded that customer preferences fall into four categories, in order of priority (highest to lowest), as follows:
> — Reliability – continuity of electrical supply.
> — Cost – lowest possible cost, accepting modest rate increases as required to refresh assets.
> — Quality – the absence of momentary interruptions and non-standard voltage levels.
> — Process – answering the phone, as accuracy of customer bills, timely construction of new service connections and upgrades to electrical services and outage notices that are given far enough ahead of the outage to allow action or reaction by the customer.

Questions:

a) Given the highest priority indicated from the customers is Reliability, what is the anticipated improvement to customer service reliability as a result of the proposed voltage conversion from 4 kV to 25 kV?

b) What is the anticipated cost impact to the customer as a result of the proposed voltage conversion project?

c) The Scorecard presented on page 175 of Exhibit 2, shows that System Reliability metrics currently meet the targets and are trending positively; what would be the anticipated improvements as a result of the proposed voltage conversion project?

d) Please describe any actions CPUC is undertaking in terms of reducing outages related to loss of supply (e.g. negotiating with Hydro One Networks).

e) What is the detailed trade-off between cost and reliability? What are the calculated costs of the reliability investments proposed in the DSP in comparison to the calculated increases in reliability or operating cost savings expected as a result of the investments?

Responses:

a) CPUC projects to maintain customer service reliability through the proactive renewal of degraded assets before an outage occurs. There is no voltage conversion planned for the 2019-2023 capital plan.

b) There is no cost impact projected in the 2019-2023 capital plan as the current DSP plan is to replace the aging infrastructure.

c) CPUC projects to maintain System Reliability and projects to continue trend positively during the 2019-2023 capital plan.

d) No actions are taken by CPUC currently to reduce outages related to loss of supply. As presented in 2-Staff-28, the majority of loss of supply outages is due to Hydro One’s network. Loss of supply due to an “act of God” are uncontrollable. CPUC restores service to its customers as quickly as possible.

e) CPUC does not project a significant improvement in its System Reliability within the DSP forecast years; rather it projects to maintain its historical performance in the DSP forecast years. The investments are a renewal of assets with the new asset to be installed in compliance with the standards to date and to accommodate a 25kV circuit.

2-Staff-17

Ref: Exhibit 2, page 71 of 221, [Distribution System Plan – 2019-2023, page 8].

Preamble:

The DSP notes:

> The long-term plan will consolidate CPUC's distribution assets at the 25-kV level, removing the interconnection points with Hydro One's 25-kV system. This project will become the singular focus of CPUC for long-term planning (the 20-year timeline). The significance of the project is such that it addresses numerous operational and business issues surrounding line loss mitigation, reliability improvements, asset renewal and standardization of system assets.

Questions:

a) Please elaborate on why it is optimal to remove the interconnection points with Hydro One's 25-kV system. What are the cost or reliability implications of removing this interconnection? For example:

   i. Will removal of interconnection increase CPUC's transformation capacity needs? If so, what additional costs will be incurred as a result of the need to supply power through new or larger CPUC-owned transformers from Hydro One's 115-kV lines?

   ii. Does removal of the interconnection result in changes in the expected frequency of Loss of Supply (LoS) events? If so, what changes are expected?

   iii. What savings are expected in Hydro One transformation connection tariffs?

   iv. Will CPUC become more reliant on a more limited number of supply points?

Responses:

a) Identified in Appendix D, the Metsco report, with the 25kV configuration, the technically complex and unreliable capacitors, and regulators currently being used to maintain system stability can be removed. There are no cost implications projected in removing the interconnection points. There are no detrimental reliability implications from the removal of interconnection points; rather it removes the risk of those assets failing and causing an outage. Additionally, installation of tie points between feeders would increase resiliency into the network and maintain service and reliability for a larger customer base instead of the majority of feeder being out of service.

i. Yes, removal of interconnections increases CPUC's transformation capacity needs. No additional projected costs are available currently and is not within the scope of the DSP forecast period.

ii. Removal of interconnections may result in little to no change in the expected frequency of LoS events.

iii. From 2018, the expected savings calculated is $39,000 which accounts for the low voltage tariff. The tariffs continue to increase annually. Therefore additional savings can be captured in future years, once CPUC builds a station and removes that feeder from HON1 station, therefore eliminating low voltage charges.

iv. It is projected that CPUC will become more reliant on a limited supply point. Furthermore, installing new assets suggests that the failure probability of the assets to be minimal; therefore, the system is expected to continue to operate and perform well.

2-Staff-18

Ref: Exhibit 2, page 79 of 221, [Distribution System Plan – 2019-2023, page 10, and page 36 table 11, OEB Appendix 2, AM Capital Expenditures].

Preamble:

The DSP notes:

> Moving forward, the asset replacement resulting from the voltage conversion from 4.16 kV to 25 kV in future DSP timeline periods is expected to have a number of positive impacts on future O&M costs:
>
> - Replacing the poles in the 4.16-kV system during the voltage conversion will reduce the frequency of pole failure and the costs associated with outage response and reactive replacement.
> - Legacy units, such as transformers and switches, that can no longer be economically maintained will be replaced and will result in a much less labour-intensive program of inspection and corrective maintenance as required, as opposed to the periodic preventive maintenance required for legacy assets.
> - The voltage conversion will reduce line losses.
> - The inherent replacement of older assets will have a positive impact on overall system reliability, resulting in lower costs associated with outage response. This investment also mitigates increased staff resource costs that would be required to deal with an otherwise more frequent rate of system failure.

Questions:

a) The DSP notes that investments in the forecast period will be focused on the Overhead Renewal Program, in parallel with preparation and planning for the voltage conversion program. Please indicate what portion, if any, of the proposed voltage conversion program is occurring in the forecast period of 2019 – 2023, including, specifically, how the pole replacements are related to the voltage conversion program.

b) Please quantify and explain the expected annual dollar value of reductions or increases in OM&A costs over the 2019 to 2023 period as a result of the voltage conversion process and other significant items, including the replacement of transformers, and the associated reduced frequency of outages?

c) On page 36, Table 11, OEB Appendix 2, AM Capital Expenditures, System O&M cost projections are blank. Please explain why System O&M cost projections are not provided at this time and revise the evidence with the actual and projected dollar values.

Responses:

a) 0% of the proposed voltage conversion program is occurring in the forecast period of 2019-2023. Pole replacements are identified as a System Renewal investment and require attention to maintain the system's service, reliability and health. Poles replaced within the forecast period will be replaced according to all current standards to date in addition to meeting the standards of fitting a 25kV feeder and its components onto the pole.

b) The voltage conversion process does not occur over the 2019 to 2023 period. Therefore, there is no change in OM&A costs. Assets for replacement are to construction standards in addition to meeting the standard of a 25kV feeder construction.

c) Refer to 2-Staff-31.

2-Staff-19

Ref: Exhibit 2, page 215 of 221, [Business Case New Book Truck]. Also, Table F-2 on page 43 of 221
Exhibit 3, page 75
Exhibit 3, Table 43 - Variance Analysis of Other Operating Revenues

Preamble

The new boom truck represented a major portion of CPUC's capital expenditures in the past five years, accounting for $389k of expenses in 2018. As noted in the supporting Business Case, factors supporting the replacement decision included:

> The current asset was expected to require extensive amount of work, which required it leaving the area, to remain in a safe operating condition. This poses larger operating costs, along with long downtimes, for repairs, affecting our ability to respond to our customers needs, as well as the shareholder.

OEB staff notes that no analysis of the costs of the alternatives regarding the replacement of the boom truck was provided by CPUC in its evidence in this proceeding.

At the first reference in Exhibit 3 noted above, CPUC stated the following:

> The Other Revenues variance for 2018 over 2017 reflects an increase of 54,219. The increase is for the most part due to a one-time revenue [sic] from the sale [sic] of a used boom truck which was [sic] replaced in 2018.

At the second reference in Exhibit 3 noted above, CPUC shows a 2018 credit amount of $50,000 in Account 4355-Gain on Disposition of Utility and Other Property.

Questions:

a) Please confirm that the boom truck was actually purchased in 2018 for a cost of $389k. If this is not the case, please explain.

b) Please confirm that the old boom truck was actually sold in 2018 for a sale or salvage value of $50k. If this is not the case, please explain.

c) Please provide the analysis of the costs of the alternatives regarding the replacement of the boom truck. If no financial analysis is available, please explain.

d) How many hours annually is the line truck used?

e) Has CPUC explored the sharing of line trucks with Hydro One? If yes, what was the outcome of these discussions? If not, why have no discussions occurred?

f) What were the actual annual maintenance costs for the old boom truck prior to its replacement?

g) What were the expected future annual maintenance costs for the old boom truck at the time of its replacement?

h) What are the expected annual maintenance costs for the new boom truck?

i) Was the expected “extensive amount of work” a one-time repair/refurbishment event or an expected ongoing program of work? In the event that it was a one-time event, did CPUC consider renting a replacement truck to provide system coverage in the interim while the truck underwent repair, in lieu of buying a new truck?

j) In Table F-2 (from Kinectrics Report1), on page 43 of 221, the current and proposed service life of ‘Vehicles – Trucks and Buckets’ is 15 years. Related questions:

    i. Please justify why a replacement of the boom truck at an age of 10 years is appropriate given the 15 year service life noted in the first sentence.
    ii. What is the accounting life over which the costs of the prior boom truck were amortized?

Responses:

a) CPUC has purchased a new boom truck at a cost of $389k.

b) CPUC did sell the old boom truck for $50k.

c) A financial analysis is available in our most recent DSP Appendix F. The truck was replaced as a necessity due to the following reasons:
    i. CPUC is an isolated LDC with the closest assistance three hours away. This mean CPUC is very reliant on the one and only unit it has on hand.
    ii. CPUC requires a safe reliable boom truck in order to perform the work required to maintain a safe, reliable distribution system.

iii. The previous truck was 17 years old, which is beyond the expected service life.

d) CPUC operates the boom truck approximately 370hrs/yr.

e) CPUC has not had a discussion with HONI on sharing a line truck. The sharing of a unit with HONI is not in CPUC or CPUC's customer' best interest. CPUC is an isolated system three hours away from the nearest LDC. This means that a shared line truck could be three hours away when CPUC may need it most which may mean a delay of service response by at least three hours or increasing a cost of asset replacement by adding additional driving time to the project. Additionally, even if the unit is in the area CPUC questions whether it will have access to it immediately since there is a possibility it may be in use on HONI circuits in the area. Furthermore, CPUC would not be aware of the unit's reliability as CPUC would have no control over maintenance on the unit. Similar issues may be experienced by HONI with sharing a unit.

f) The old boom truck maintenance expense varied from year to year depending on what needed to be done on the unit. The older the unit, the more frequent chance of a maintenance cost being incurred. In the past, CPUC was very fortunate to be able to have the repairs performed by the Township mechanic. This saved the utility a lot of expense over the years. On average, CPUC spent $2500/yr. for the last four years.

g) Future maintenance costs are difficult to predict. The previous boom truck was 17 years old, and it would have only taken one major failure to put the unit out of commission for an extended period of time. This would require that CPUC find, rent and bring a replacement unit to the service area and then getting familiar with the operation of the unit. The repairs would be most likely performed out of town adding to the cost.

h) The maintenance costs on the new truck will be the same as on the previous truck. The new boom truck expenses will be the usual cost of fuel, regular maintenance, annual safety inspection for the truck, annual safety inspection because the unit is a man lifting device and requires special licensing.

i) Though it is difficult to predict repairs required, CPUC projects it would have been an ongoing program of work. CPUC felt it would not have been in the interest of the company to deal and manage with renting a unit. To reiterate, CPUC is an isolated LDC, and a back-up unit is not in proximity to CPUC.

j)

   i. The replaced boom truck was from 2002 – an age of 17 years, which is beyond the proposed service life found in the report.
   ii. The old boom truck was amortized over 15 years.

2-Staff-20

Ref: Exhibit 2, pages 35, 36 and 38 of 221

Preamble:

Table 11 – OEB Appendix 2-AB Capital Expenditures provides a summary of planned capital expenditure against actual expenditure between 2012 and 2018.

In certain cases, numbers in Table 11 do not appear to match numbers in Table 13 that follows on page 38 of 221. (For example, total system renewal expenditure is listed as $45,855 for 2015 in Table 13, whereas this number appears in 2016 in Table 11.) Also, in Table 11, Totals do not add in the Actual columns for 2013, 2014, and 2015.

Questions:

a) Please confirm that the amounts shown for actual expenditures for years 2013, 2014, 2015, and 2016 are correct. Please provide an updated table if they are not correct.

b) What were the main reasons for the overruns in capital expenditures in the years between 2013 and 2018 inclusive, when comparing Planned versus Actual?

c) Given the large apparent variances between actual capital expenditure and planned capital expenditure over the period 2012 through 2018, how much confidence does CPUC have in its forecast capital plan for 2019 – 2023? Please provide additional evidence that the forecast capital plan is realistic and achievable.

Responses:

a) In the absence of a previous DSP, CPUC used the last board approved capital budget as a "planned". The actual budgets for previous years are shown in the table below. Yes, we confirm they are the actuals.

Year	2012	2013	2014	2015	2016	2017	2018	2019
Budgeted	$51,790	$56,835	$60,018	$45,781	$37,377	$37,088	$476,661	$80,667
Capex	$462,048	$88,227	$43,923	$101,176	$36,293	$24,057	$476,662	

b) The 2018 and 2019 budgets are supported by a DSP and other studies which were not required in the last cost of service. CPUC has confidence in the budgets that have been presented. However, the utility cannot plan for unforeseen events such as weather-related events or government mandated programs such as the replacement of conventional meters to smart meters for example.

c) Same as b) above

2-Staff-21

Ref: Exhibit 2, pages 72 of 221 [Distribution System Plan – 2019-2023, page 9].

Preamble:

On page 9 of the DSP, the following claims are made:

Presently, CPUC is undertaking the following initiatives that will result in further additional cost savings for this DSP period:

- CPUC is sampling its meters to determine if they are operating and reading an acceptable level. Should the meters be tested positive, CPUC can extend the seal life of its meters by eight years, further reducing the costs and allowing CPUC to invest in its assets
- CPUC is completing a station power transformer dehydration in order to extend the life of the station transformers. This action resulted in mitigating the impact on the customer bill, and it allowed for investments to be directed into the asset renewal program.

Questions:

a) What is the current investment plan for meter replacement? Please quantify. Does it assume that meter life can be extended for eight years?

b) In the event that seal life cannot be extended, what is the financial impact on CPUC's capital expenditure plan?

c) Will the expenditure to complete the station power transformer dehydration be carried out under O&M expenses or will there be capital investment required? What are the expected costs of this dehydration?

Responses:

a) Within the forecast period, smart meters will be purchased for large users and installed by 2020 as mandated by the OEB. No additional investment plans for meter replacements is projected. The meter sampling test for re-verification returned positive. Therefore, the meter life can be extended for eight additional years.

b) CPUC tested the smart meters with a returning test result in favor of extending the seal life of the smart meters. Therefore, there is no financial impact on CPUC's capital expenditure plan.

c) The station power transformer dehydration was completed in 2018 and carried out as a capital investment. There are no additional costs associated with the work in the forecast period. The total cost was $23,500.

2-Staff-22

Ref: Exhibit 2, pages 102 of 221 [Distribution System Plan – 2019-2023, page 39].

Preamble:

On page 102 of Exhibit 2, CPUC claims:

> For this initial planning process cycle, CPUC has developed an asset registry in its Geospatial Information System ("GIS") and started collecting asset data. This system is in its infancy and currently has limited attributes captured for each asset class. It is CPUC's intention to continue to expand the attributes measured and collected to comprehensively bridge information gaps that were identified in the initial assessment.

Questions:

a) What is the current state of the data capture for the assets named?

b) What timeline is anticipated to complete the data capture of all asset classes?

c) Has the data capture process been budgeted for within the 2019 – 2023 rate application cycle? If so, please provide details and budget estimates.

d) What are the expected capital and OM&A savings to be realized over the 2019 to 2023 period from moving towards an asset management replacement program that is not just strictly based on age, but is also based on asset condition?

Responses:

a) To date, CPUC estimates to have collected nearly 100% of in-service pole data. For distribution transformers, CPUC estimates to have collected approximately 15% asset nameplate data. For distribution switches, 0% of the data is digitized, though locations are recorded on a paper copy of the distribution system. For overhead conductors, CPUC estimates to have 5% of asset data collected, namely the total length of conductors on a feeder rather than by segments. For underground cable, CPUC estimates 25% of asset data collected. Lastly, for station transformers CPUC estimates to have collected near 100% nameplate data.

Additionally, CPUC performs IR scans of its entire system and retains that information.

b) Asset data collection is a part of CPUC's continuous improvement and asset management processes. Achieving 100% of data collection requires extensive effort with the already limited personnel at CPUC. CPUC plans to capture as much data as possible, though it recognizes it is an on-going and continuous process. Within the DSP forecast period, CPUC intends on collecting a more established asset registry on its remaining major asset classes. CPUC cannot establish targets as the data collection requires resources that CPUC has already focused on capital and maintenance projects.

c) The data capture process has no additional costs as the process is implemented within CPUC's maintenance and inspection activities which follow the minimum requirement of the DSC.

d) Quantifying the savings from an asset management replacement program that is not strictly based on age, but is also based on asset condition, assumes that condition assessment results will indicate an extension of asset life. However, this is not always the case as a condition could indicate a shortening of asset life and subsequent increase in costs over any given time period. Quantifying either of these impacts would require asset condition information.

CPUC intends to move towards an asset management replacement program that is not strictly based on age, but is also based on asset condition, in order to increase the fidelity of its asset management decisions by considering more relevant information.

2-Staff-23

Ref: Exhibit 2, page 131 [Distribution System Plan – Section 4.2.2.2, page 67- 68]
Exhibit 5, section 5.5.4, Long-Term Debt

Preamble:

At the above noted first reference, CPUC stated on page 131, C in the Capital Expenditure Plan Section 4.2.2.2, CPUC claims:

> The two scenarios developed and evaluated through CPUC's methodology are:
>
> 1. Intrinsic Approach – This scenario is based on operating the distribution system status quo. Under this scenario, CPUC operates the assets along with a predetermined budget that includes like-for-like replacement of equipment at the end of life and operating the local grid in much the same way it has been in the past. This approach targets approximately 1% of the asset base for a replacement for every year over 20 years. This scenario pushes back the voltage conversion past the 20-year target, which limits CPUC's capability to reduce line losses. This approach utilizes both the minimum and sustain service level.
>
> 2. Investment Optimization Approach – This scenario describes an investment approach that optimizes the operation of the distribution system and recapitalizes CPUC to finance the investments. This approach increases the target of 2% asset renewal in the first five years and increases in the next 15 years as CPUC prepares to do a voltage conversion on their system. This allows for CPUC to complete a voltage conversion within a 20-year timeline and address the line loss to the reasonable Ontario average of 3.82%. This approach utilizes both the improve and optimize service level.

At the above noted second reference, CPUC stated the following:

> CPUC is not forecasting any debt in 2018 & 2019. However, it is likely that the utility will need to obtain long term debt in the near future if studies and analysis of the current substation show that it will need to be replaced. If this event occurs, the utility will seek long-term debt from either a financial institution or Infrastructure Ontario. CPUC does not have any promissory notes to present.

Questions:

a) What would be the estimated expected line loss percentage every year over the next 20 years on a yearly basis in the Intrinsic Approach scenario? Please explain how this loss impacts cost for customers.

b) What would be the estimated line loss percentage every year over the next 20 years in the Investment Optimization Approach scenario? Please explain the benefits to customers in terms of cost savings.

c) Please explain what the exact asset renewal percentage is proposed in the next 15 years under the Investment Optimization Approach scenario.

d) Please provide capital and OM&A cost models over the 2019 to 2023 period, and beyond 2023 where available, to show the assumptions and results of the analysis for each of these proposed scenarios.

e) Please provide more detail as to CPUC's above-noted statement in Scenario 2 that it plans to "recapitalizes CPUC to finance the investments." In its explanation, CPUC should include a dollar impact on both its proposed 2019 capital structure for rate-making purposes and proposed 2019 actual capital structure for financial statement purposes, as well as consider CPUC's above-noted statement in section 5.5.4 of its application.

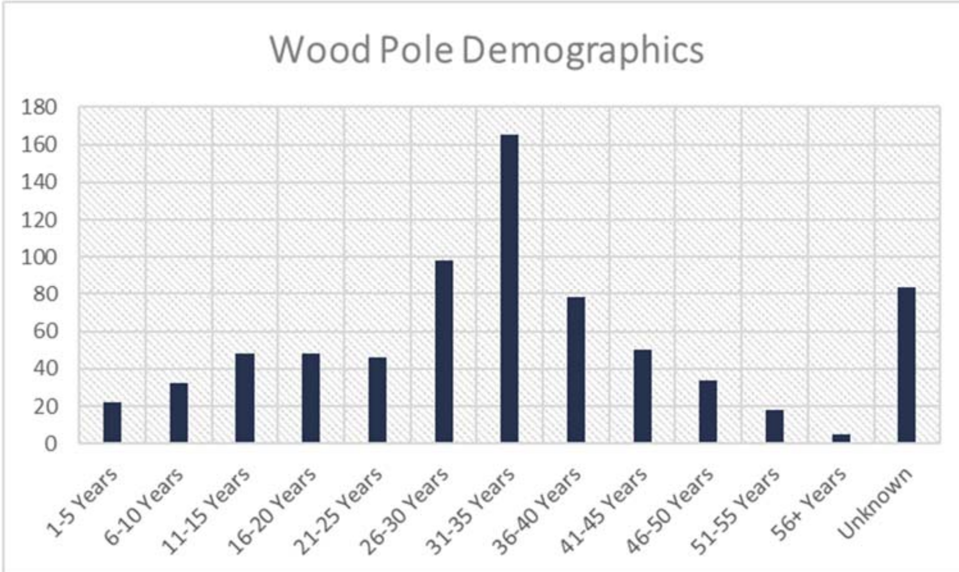
Responses:

a) In reference to the Metsco prepared a report (Appendix D of the DSP), over the next 20 years, the estimated line loss percentage as a combination of feeders F2, F8 and F9 is 24.64%. The financial loss is equivalent to approximately $123,400 per year. This loss is incurred by the customer as part of their billing cycle.

b) In reference to the Metsco prepared report and 2-Staff-14, the estimated line loss percentage as a combination of feeders F2, F8 and F9 are shown in the table below over the 20-year period. The financial savings is equivalent to $119,900 per year, or a reduction in line loss cost of approximately 97%.

Time Period	Estimated Line Loss Percentage
2019-2028	24.64 %
2029-2032	21.00 %
2033-2036	8.20 %
2037 and moving forward	0.70 %

c) Presented within the DSP and shown below in the figure, CPUC is estimating to replace poles that are in poor condition and beyond their useful life over the 15-year period after 2023. Based on age, the current percent estimate is 67%.



Furthermore, as part of the voltage conversion, 100% of the substation transformers will be renewed. 67% of the overhead conductors will be renewed/upgraded to meet the 25kV standard. The percentage of distribution transformer renewals is currently estimated to be 40%.

d)

Year	Scenario 1	Scenario 2
2019	$ 64,333	$ 80, 667
2020	$ 64,333	$ 80, 667
2021	$ 64,333	$ 80, 667
2022	$ 64,333	$ 80, 667
2023	$ 64,333	$ 80, 667

For Scenario 1, the in-service assets age and condition would have to be analyzed to determine the intrinsic approach expenditures beyond 2023 to sustain service level.

For Scenario 2, please refer to 2-Staff-14 for the estimate forecast capital expenditure for beyond 2023.

In both Scenarios, the O&M expenditures would remain the same. O&M expenditures are the minimum amounts required for CPUC to comply with the DSC, maintaining its assets at the expected inspection/maintenance cycle

e) The statement found in Scenario 2 may allude to forecast years beyond the current DSP forecast period of 2019-2023. There is no dollar impact on both the 2019 capital structure for rate-making purposes and proposed 2019 actual capital structure for financial statements purposes within the current DSP forecast period.

2-Staff-24

Ref: Exhibit 2, page 132 [Distribution System Plan – Section 4.2.7, page 132].

Preamble:

On page 132, in the Capital Expenditure Plan Section 4.2.7, CPUC claims:

> Under the new Conservation First Framework for the 2015 to 2020 period, the provincial CDM focus has shifted to only energy savings and CPUC was assigned a target of 1.152 GWh of cumulative energy savings. CPUC has achieved 61% of its energy savings forecast as of the end of 2017.

Questions:

a) Please elaborate on the initiatives that have had the most impact in the Energy Savings achieved with some indicative metrics for initiatives such as coupon saving events, small business lighting program, or web energy conservation tips.

b) Please provide an explanation as to why Energy Savings have declined relative to 2015 levels according to Figure 35 in this section.

Responses:

a) CPUCs assigned target from the IESO is 1,045,702 kWh (1.045GWh). 1.152 GWh was the target allocated in the original LDC CDM Plan. At the end of 2017, CPUC had achieved 67% of the target.

Residential programs represented 58.4% of savings achieved to the end of 2017, with most of the savings coming from the coupons and instant discounts program. The residential programs overall represented 39% of the total portfolio savings towards the target.

Business programs, specifically the RETROFIT program represented 41.6% of savings achieved to the end of 2017. Overall, business programs represented 28% of portfolio savings.

Program	kWh	% of savings achieved to 2017	% of cumulative savings toward target
Coupons / instant discounts	403,209	57.7%	39%

Heating and cooling	1,056	0.2%	0.1%
Whole home	3,593	0.5%	0.3%
Retrofit	287,996	41.2%	28%
Small business lighting	3,075	0.4%	0.3%
Total	698,929	100%	67%

b) In 2015, a large Retrofit project was completed at the local hospital which represented 218,983 kWh, approximately 21% of the total savings towards the target. In total, 2015 represented 27% of the total savings achieved; 2016 represented 20% savings towards target and 2017 another 20% towards the target.

2-Staff-25

Ref: Decision and Order, November 29, 2012[3]

Preamble:

As per CPUC's 2012 cost of service proceeding,[4] for rates effective May 1, 2012, and implemented December 1, 2012, the following items were noted by the OEB in its Decision and Order issued on November 29, 2012:

- Page 9 – The OEB stated that it will allow CPUC its proposed investments for 2012. However, going forward it is the OEB's expectations that CPUC carefully consider its investments in its distribution system with a view to manage overall costs to run the distribution system. The OEB noted that this will require a better understanding of system losses and the long-term impacts of distribution system upgrades.

- Page 10 – The OEB stated that it expects CPUC to continue to consider the results of its asset assessments and to focus on what needs to be done and to spend what is required to maintain its system reliability.

- Page 10 – The OEB stated that CPUC is expected to be able to defend the prudence of its spending on all forms of capital in the establishment of its rate base in its next rebasing application. CPUC submitted that the development of its AMP will assist in the management of system losses. The OEB stated that it considers this element of CPUC's intended AMP to be an important investment in that it may lead to a reduction in overall long-term operating costs.

Questions:

a) Please explain how CPUC has addressed the above noted OEB concerns articulated in its 2012 cost of service proceeding decision.

Responses:

a) Over the course of the historical period, CPUC managed and considered its investments to maintain the distribution system. Renewal investments to date were frugal and only assets that are near failure were replaced. To support the replacement of assets, assessments, consisting of testing and

[3] EB-2011-0322
[4] EB-2011-0322

visual inspections, were completed to determine the assets criticality to failure. For example, wood pole inspections were completed to determine which wood poles require intervention.

CPUC notes there are four investments that brought CPUC's net capital expenditures above the 2012 OEB approved budget. Below is the list of investments with actual costs and CPUC's reasoning as to why they were required.

Year	Investment	Cost	Reason
2012	Transferring Smart Meter account	$439,701	The investment was required in order to transition customer billing biannually to monthly to alleviate the bill shock customers experienced and to inform customers of important announcement on a more often reoccurring basis
2013	Burman Asset Management Plan	$40,000	To assist CPUC with developing system plans and alternatives to best address its issues and meet customer needs.
2015	Burman Energy Survey & Software Support	$54,800	CPUC commissioned a Customer Engagement study to fulfill the OEB requirement when developing the DSP. Furthermore, CPUC began collecting data for a digitized GIS database as an added efficiency value for CPUC transition away from a paper-based record format.
2018	Boom Truck	$389,010	A business case was provided as part of the DSP.

Furthermore in 2018, CPUC commissioned a report to further understand its system losses and alternatives impacting the long-term load found on the current substations. Based on the findings of the report, CPUC developed its current five year forecast plan for the current DSP.

2-Staff-26

Ref: May 16, 2017 letter to the OEB from CPUC regarding the request for deferral of its cost of service application

Preamble:

At the above-noted reference, page 3, CPUC stated the following:

> The timing of Major Capital Investment
>
> With consideration to all the above justifications, the main reason for the request for a deferral is that the utility plans on building a substation in 2018/2019. At this point, CPUC does not anticipate the substation to be in service in 2018 and believes that such a significant capital investment should be included in the Distribution System Plan, and the utility's Test Year, therefore, CPUC believes that rates effective January 1, 2019, would be appropriate given these circumstances.

Questions:

a) Please provide more detail as to why CPUC did not build its substation in 2018/2019 as outlined in its May 16, 2017 letter to the OEB.

Responses:

a) At the time CPUC filed for a deferral, it was CPUC's intention on building a substation within the 2018/2019 period. Post-filing the deferral letter, CPUC presented the proposed budget to its Board of Directors (the "Board"). Upon reviewing the budget, the Board rejected the proposed plan as it would result in a cost increase for customers without adequate consultation and feedback from the public. With the decision made, CPUC commissioned a study for the purpose of evaluating the utility's load flow, substation capacity and redundancy of the system. The study included findings with respect to optimizing the system arrangement to minimize losses, maximize voltage support and to distribute loading evenly. Furthermore, the study identified alternatives for CPUC to consider, with one alternative being to delay the substation construction beyond the five-year forecast period of the current DSP. From the analysis, CPUC delayed the building of a new substation.

2-Staff-27

Ref: Exhibit 2, DSP, Table 5 Historical and forecast capital expenditures and system O&M
Exhibit 2, DSP, page 8

Preamble:

At the above-noted reference, the following table is shown:

Table 5 Historical and forecast capital expenditures and system O&M

Category	Historical ($ '000)					Forecast ($ '000)				
	2014	2015	2016	2017	2018*	2019	2020	2021	2022	2023
System Access (Gross)	-	0.5	1.0	19.7	8.0	-	-	-	-	-
System Renewal (Gross)	18.9	45.9	35.3	4.4	34.4	80.7	80.7	80.7	80.7	80.7
System Service (Gross)	25.0	-	0.1	-	32.5	-	-	-	-	-
General Plant (Gross)	-	54.8	-	-	401.8	-	-	-	-	-
Gross Capital Expenses	43.9	101.2	36.4	24.1	476.7	80.7	80.7	80.7	80.7	80.7
Contributed Capital	-	-	-	-	-	-	-	-	-	-
Net Capital Expenses after Contributions	43.9	101.2	36.4	24.1	476.7	80.7	80.7	80.7	80.7	80.7
System O&M	744.7	730.6	744.0	716.6	797.8	813.8	805.8	809.8	807.8	808.8

**8 months of actual expenditures included in 2018*

At the above noted second reference, CPUC stated the following:

> Investments into the categories of System Access, System Service and General Plant in this DSP period will be minimal and under the materiality threshold set out in the Filing Requirements.

Questions:

a) Please explain why there are $0 historical and forecasted capital contributions.

b) Even if the forecasted System Access, System Service, and Gross Plant capital expenditures over the 2019 to 2023 period are expected to be immaterial, please provide an updated table showing values for these types of capital expenditures over the 2019 to 2023 period.

c) Please explain why an exact amount of $80.7k is forecasted over the 2019 to 2023 period for System Renewal capital expenditures when in it is likely that the amounts may differ.

Responses:

a) There have been zero capital contributions over the historical period. CPUC does not project any capital contributions over the forecast period.

b) Please refer to 2-Staff-31 for an updated expenditures table.

c) CPUC is projecting the scope of work to be similar in nature through the forecast period. The scope of work is to replace poles that are in poor condition or at risk of failing and require intervention. CPUC intends on committing to the forecast expenditure projection with minimal variance.

2-Staff-28

Ref: Exhibit 2, DSP, page 19, section 2.3.1.2.1 Methods and Measures

Preamble:

At the above noted reference, CUPC indicated that loss of supply outages occurs due to problems associated with assets owned by another party then CPUC or the bulk electricity supply system.

Question:

a) Please provide more detail regarding the timelines and details of loss of supply received from Hydro One Networks when an unplanned outage occurs.

Responses:

Date	Reason	Customers Affected	Duration (HRS)
23 July 2013	Tree on Hydro One line	340	0.5
10 September 2014	Fault on Hydro One circuit, going by protection to station reclosure causing PUC customers to lose power (occurred twice in same day)	340	0.5
28 September 2014	Outage on HONI side knocking out all CPUC	1260	4
3 October 2014	Tree on F4 Hydro One Circuit	340	1
15 October 2014	Hydro One problem causing CPUC customers to lose power	340	1
9 March 2015	Bird contact in HONI station	340	5.5
2 August 2015	Bird contact damaging metering equipment	340	5
1 November 2015	Scheduled Outage HONI W2C	1208	6
18 November 2015	HONI F4 feeder problem opening station reclosure affecting PUC F1 feeder	340	1
14 December 2015	HONI F4 feeder problem opening station reclosure affecting PUC F1 feeder	340	0.5
17 December 2015	HONI F4 feeder problem opening station reclosure affecting PUC F1 feeder	340	1
1 May 2016	Scheduled Outage HONI W2C	1208	6
5 June 2016	Scheduled Outage HONI W2C	1208	8
15 July 2016	Bird contact HONI station affecting PUC F1 feeder	340	1
30 July 2017	Scheduled Outage HONI W2C	1208	7.5
5 August 2017	Fault on HONI F4 affecting PUC F1 feeder	340	1
10 September 2017	Problems on the WC2	1208	7
21 September 2017	Bird contact HONI station affecting PUC F1 feeder	340	4.5
6 May 2018	Scheduled Outage HONI W2C	1208	4
27 May 2018	Scheduled Outage HONI W2C	1208	4

28 October 2018	Scheduled Outage HONI W2C	1208	2.5

2-Staff-29

Ref: Exhibit 2, Table 11
Excel Appendix 2-AB

Preamble:

The revised November 26, 2018 Exhibit 2, Table 11, PDF Appendix 2-AB has been reviewed and there are still discrepancies, compared to the Excel Appendix 2-AB. For example:

2013 Plan Total Expenditure shows $8,290 in the PDF and $58,290 in the Excel
2014 Plan Total Expenditure shows $8,290 in the PDF and $58,290 in the Excel
2015 Plan Total Expenditure shows $8,290 in the PDF and $58,290 in the Excel
2013 Actual System Access shows $39,701 in the PDF and $880 in the Excel
2013 Actual System Renewal shows $6,941 in the PDF and $12,647 in the Excel
2013 Actual System Service shows $5,406 in the PDF and $0 in the Excel
2013 Actual General Plant shows $0 in the PDF and $74,700 in the Excel
2013 Actual Total Expenditure shows $62,048 in the PDF and $88,227 in the Excel
2014 Plan System O&M shows $0 in the PDF and $205,440 in the Excel
2015 Plan System O&M shows $0 in the PDF and $205,440 in the Excel
2014 Actual System Access shows $880 in the PDF and $0 in the Excel
2014 Actual System Renewal shows $12,647 in the PDF and $18,923 in the Excel
2014 Actual System Service shows $0 in the PDF and $25,000 in the Excel
2014 Actual General Plant shows $4,700 in the PDF and $0 in the Excel
2014 Actual Total Expenditure shows $8,227 in the PDF and $43,923 in the Excel
2015 Actual System Access shows $0 in the PDF and $1,000 in the Excel
2015 Actual System Renewal shows $18,230 in the PDF and $45,855 in the Excel
2015 Actual System Service shows $25,000 in the PDF and $0 in the Excel
2015 Actual General Plant shows $0 in the PDF and $54,800 in the Excel
2015 Actual Total Expenditure shows $3,923 in the PDF and $101,655 in the Excel
2016 Actual System Access of $1,000 shows no discrepancy between the PDF and Excel
2016 Actual System Renewal shows $45,855 in the PDF and $35,193 in the Excel
2016 Actual System Service shows $0 in the PDF and $100 in the Excel
2016 Actual General Plant shows $54,800 in the PDF and $0 in the Excel
2016 Actual Total Expenditure shows $101,655 in the PDF and $36,293 in the Excel

Question:

a) Please resolve the above noted discrepancies.

Responses:

a) CPUC confirms that the information presented at Tab App.2-AB_Capital Expenditures in the file entitled “CPUC 2019_Filing

Requirements_Chapter2_Appendices_20181126.xls” filed on November 26, 2018, is correct..

2-Staff-30

Ref: Exhibit 2, Appendix 2-AB
Excel Appendix 2-AB

Preamble:

OEB staff notes that the 2020, 2021, 2022, 2023 System O&M is blank in both the PDF and Excel versions of Appendix 2-AB. OEB staff also notes that the column 2018 "Actual" has been filled out when the year was not yet completed at the time of CPUC filing its application.

Question:

a) Please include values for 2020, 2021, 2022, 2023 System O&M in both the PDF and Excel versions of Appendix 2-AB, versus the $0 values that current exist in this evidence.

b) Please explain why the column 2018 "Actual" has been filled out when the year was not yet completed at the time of CPUC filing its application.

Responses:

a) CPUC has not yet prepared nor presented its OM&A budgets for 2020 to 2023 to its Board of Directors. For illustrative purposes, CPUC has applied a 1.5% inflation factor. Staff can find the projections in the revised Chapter 2 Appendices.

b) Please see OEB instructions below the table which state that "…the applicant should include their planned budget **in each subsequent historical year up to and including the Bridge Year**."

2-Staff-31

Ref: Exhibit 2, DSP Table 5 and Table 24
Excel Appendix 2-AB

Preamble:

OEB staff has compared the revised November 26, 2018 version of Table 5 and Table 24 in the DSP to Excel Table 2-AB. There are still some very minor discrepancies between the two tables relating to Capital Expenditures, but these items do not require updating due to small size of the discrepancies. However, there are major discrepancies between the System O&M in Table 5 and Table 24 of the DSP to the Excel Appendix 2-AB.

For example, comparing Table 5 and Table 24 of the DSP to the Excel Appendix 2-AB:

2014 Actual System O&M shows $744,700 in the DSP and $223,211 in the Excel Appendix 2-AB
2015 Actual System O&M shows $730,600 in the DSP and $208,239 in the Excel Appendix 2-AB
2016 Actual System O&M shows $744,000 in the DSP and $236,332 in the Excel Appendix 2-AB
2017 Actual System O&M shows $716,600 in the DSP and $237,909 in the Excel Appendix 2-AB
2018 Actual System O&M shows $797,800 in the DSP and $247,400 in the Excel Appendix 2-AB

For example, comparing Table 24 of the DSP to the Excel Appendix 2-AB (Note that Table 5 of the DSP does not have "Plan" System O&M for 2014 through 2018, only "Actual"):

2014 Plan System O&M shows $0 in the DSP and $205,440 in the Excel Appendix 2-AB
2015 Plan System O&M shows $0 in the DSP and $205,440 in the Excel Appendix 2-AB
2016 Plan System O&M shows $328,000 in the DSP and $205,440 in the Excel Appendix 2-AB
2017 Plan System O&M shows $321,200 in the DSP and $205,440 in the Excel Appendix 2-AB
2018 Plan System O&M shows $327,600 in the DSP and $205,440 in the Excel Appendix 2-AB
2019 Plan System O&M shows $813,800 in the DSP and $244,370 in the Excel Appendix 2-AB
2020 Plan System O&M shows $805,800 in the DSP and blank in the Excel Appendix 2-AB

2021 Plan System O&M shows $809,800 in the DSP and blank in the Excel Appendix 2-AB
2022 Plan System O&M shows $807,800 in the DSP and blank in the Excel Appendix 2-AB
2023 Plan System O&M shows $808,800 in the DSP and blank in the Excel Appendix 2-AB

Question:

a) Please resolve the above-noted discrepancies.

Responses:

CPUC provides a revised Table 5 and Table 24 that are part of its DSP below. CPUC notes it has made a mistake with the inclusion of the total OM&A costs and has adjusted its tables accordingly.

Over the 2014-2018 period, the CPUC experienced an annual increase of 3%. O&M costs are driven by the need to maintain the system's service and its assets. CPUC projects its forecast O&M expenditures to be in line with historical performance.

2-Staff-32

Ref: February 22, 2019, OEB Staff Summary of Community Meeting, page 3 and page 4

Preamble:

Page 3 and page 4 of the OEB Staff Summary of Community Meeting outlined concerns of customers. Customers sought clarification on the following items:

1. Information needs to be provided regarding the actual and expected work done on transformers and whether CPUC had looked at efficiencies.

2. Information needs to be provided to address customers' concerns over system reliability. Information needs to be provided if emergency funds have been set aside for transformers, or if any plans had been put in place to deal with outages.

3. Regarding Goldcorp Inc. and RYAM Lumber, information needs to be provided whether CPUC had looked into the possibility of connecting these two companies when they first started operations.

Question:

a) Please describe how CPUC plans to address the above-noted concerns from customers.

Responses:

1) Over the past number of years Chapleau PUC has been performing ongoing maintenance to the Transformer Station, listed below:
    - Since 2003 CPUC has performed TX oil testing annually along with Infrared scanning.
    - In 2004 CPUC contracted HON1 to perform a Transformer Station Maintenance and Assessment.
    - In 2004 CPUC replaced 3 older regulators with new ones.
    - In 2012 CPUC had 3 regulators refurbished and placed into service.
    - In 2013 CPUC contracted Stark International to perform Station Transformer oil cleaning and re-inhibiting.
    - In 2018 CPUC contracted Stark International to perform Transformer oil de-hydration and gasket repairs.

The expected life of the Two Station Transformer is projected to be 5-10 years.

2) System reliability is dealt with by having an investment fund. Depending on the time of year CPUC can transfer load from the faulty Transformer to the working Transformer till repairs or replacement can be made, (CPUC also has insurance coverage for this type of situation). If this is not an option that CPUC would be looking across the province for a portable station to put into service until repairs or replacements can be found.

3) CPUC is unable to connect to either Goldcorp or RYAM Lumber because these industrial customers are located outside CPUC's service area. They are in Hydro One's service area. CPUC did discuss the shared building of a new 25 KV substation with Goldcorp, that would serve both their mine's needs, and replace CPUC's 4 KV transformers. However, the capital involved in such a large substation was far beyond CPUC's capacity.

2-Staff-33

Ref: Exhibit 2, page 47 to 55
Exhibit 8, page 27
Exhibit 8, Table 16 – OEB Appendix 2-R Calculation of Proposed Loss Factor
Decision and Order, RRRP charge and WMS rate, December 20, 2018[5]
Tariff Sheet, January 7, 2019
Reporting and Record Keeping Requirements (RRR) 2.1.5.4 as at December 31, 2017

Preamble:

At the above noted first reference, CPUC has presented its cost of power calculation.

At the above noted second reference, CPUC has stated that its requested total loss factor is 1.0500.

At the above noted third reference, CPUC has indicated that the six year average of its total loss factor is 1.0757.

At the above noted fourth reference, the OEB has issued new rates as follows, effective January 1, 2019.

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

OEB staff notes that CPUC has used loss adjusted kWh or "uplifted" kWh for certain components of its cost of power calculation. However, CPUC has not used its requested total loss factor of 1.0500 in these calculations. Instead a different number of 1.0570 is used in the calculations, which is CPUC's six year average of its total loss factor.

OEB staff notes that a WMS rate of $0.0036 is used in the cost of power calculation instead of the updated charge of $0.0034, which includes CBR. The CBR charge is also not shown as a separate line on CPUC's tariff sheet.

OEB staff notes that a RRRP rate of $0.00030 is used in the cost of power calculation instead of the updated charge of $0.00050.

OEB staff observes that the WMS and RRRP calculations for the following rate classes used kW as a billing determinant to calculate the WMS and RRRP cost of power, instead of kWh:

- GS > 50 to 4,999 kW rate class

[5] EB-2018-0294

- Sentinel Lighting
- Street Lighting

OEB staff notes that the smart meter entity charge is proposed to be recovered from the GS > 50 to 4,999 kW rate class, in addition to the Residential and the GS < 50 kW rate classes. OEB policy does not include the recovery of this charge from the GS > 50 to 4,999 kW rate class.[6] OEB staff observes that the smart meter entity charge is calculated on a per customer basis but CPUC's calculation does not multiply this charge by twelve months. CPUC has factored a monthly amount into the cost of power calculation instead of an annual amount.

OEB staff notes that in CPUC's Appendix 2-Z filed as part of Exhibit 2, CPUC has classified the following:

1. 12,775,802 kWh for the Residential rate class as RPP. Upon further review of RRR 2.1.5.4, the components of the 12,775,802 kWh are as follows:

    - 12,723,720 kWh are RPP metered consumption
    - 52,082 kWh relate to consumption of retailer customers

2. 4,702,580 kWh for the GS < 50 kW rate class as RPP. Upon further review of RRR 2.1.5.4, the components of the 4,702,580 kWh are as follows:

    - 4,507,872 kWh are RPP metered consumption
    - 194,708 kWh relate to consumption of retailer customers

3. 6,797,046 kWh for the GS >50 to 4,999 kW rate class as non-RPP kWh eligible for the GA Modifier. Upon further review of RRR 2.1.5.4, the components of the 6,797,046 kWh are as follows:

    - 6,565,386 kWh are SSS metered
    - 231,660 kWh relate to consumption of retailer customers

CPUC has filed a similar PDF version of Appendix 2-Z in its Exhibit 2 PDF, when compared to the OEB's model included in the Excel Chapter 2 Appendices, Appendix 2-Z. OEB staff observes that CPUC did not use the OEB's model to calculate the commodity charge for the cost of power, although the output is the same. If CPUC updates Appendix 2-Z as a result of the interrogatories below, CPUC may populate Appendix 2-Z that was included in the Chapter 2 Appendices filed on July 18, 2018 by the OEB.

Questions:

[6] EB-2017-0290, IESO / SME Application, March 1, 2018 Decision and Order, page 5

a) Where uplifted volumes are incorporated, please revise the cost of power calculations using the total loss factor that may be used considering CPUC's response to IR# 8-Staff-73 and 8-Staff-75.

b) Please revise the cost of power calculations for WMS using the updated charge of $0.0034, which includes CBR. Please also revise the tariff sheet and bill impacts, including separate lines on the tariff sheet for CBR.

c) Please revise the cost of power calculations for RRRP using the updated charge of $0.00050. Please also revise the tariff sheet and bill impacts.

d) Please revise the cost of power calculations for WMS and RRRP for the following rate classes using kWh, instead of kWh:

- GS > 50 to 4,999 kW rate class
- Sentinel Lighting
- Street Lighting

e) Please confirm and explain that CPUC does not charge a smart meter entity charge to its GS > 50 to 4,999 kW customers.

f) Please revise the cost of power calculation for the smart meter entity charge as follows:

   i. Remove the amount proposed to be recovered from the GS > 50 to 4,999 kW rate class
   ii. Revise the calculation of this charge to generate an annual amount to be recovered from customers (i.e. multiply the charge by 12 months).

g) Please revise the cost of power calculations using the low voltage charges that may be used considering CPUC's response to IR# 8-Staff-72.

h) Please revise the cost of power calculations using the revised RTSRs that may be used considering CPUC's response to IR# 8-Staff-71.

i) Please explain whether the entire 12,775,802 kWh for the Residential rate class is RPP-eligible. If this is not the case, please update the cost of power calculation.

j) Please explain whether the entire 4,702,580 kWh for the GS < 50 kW rate class is RPP-eligible. If this is not the case, please update the cost of power calculation.

k) Please explain whether the entire 6,797,046 kWh for the GS >50 to 4,999 kW rate class is eligible for the GA modifier. If this is not the case, please update the cost of power calculation.

l) Please refile the calculation of the commodity charge using the OEB's model of Appendix 2-Z that was included in the Chapter 2 Appendices filed on July 18, 2018 by the OEB.

Responses:

a) Updated

b) Updated

c) Updated

d) Updated

e) Updated

f) See i) and ii) below
   i. Redundant IR see response to e)
   ii. No change as the total per class is multiplied by 12 months

g) Done

h) CPUC confirms that the entire consumption for the Residential Class is RPP eligible

i) CPUC confirms that the entire consumption for the GS<50 Class is RPP eligible

j) Confirmed

As explained in the letter of incomplete, as well as over the phone to OEB Staff, at the time of the filling of the application, Appendix Z was completely locked for editing. CPUC further notes that it was directed to talk to Andrew Frank of the OEB who also tested and confirmed that the Appendix Z was completely locked.
Furthermore, since the utility does not have any Class A customers, the calculations provided as a separate file amount to the same commodity projection which have been updated to reflect the changes above.

2.0-VECC-4

Reference: Appendix 2-AB –DSP Table 5, Section 5.2.1

a) In the past cost of proceeding CPUC forecast an annual capital budget of 58k per year. In the event the actual capital expenditures were significantly different from that in every year. Please explain why the Utility's capital planning was unlike its actual spending. Specifically address what steps are being taken to improve the planning process at CPUC.
b) In this Application CPUC has continued the practice of setting a fixed and standard capital expenditure ($80.7k per annum) without reference to any specific project (other than generally pole replacement). Why should the Board expect more accurate planning-to-actuals going forward?
c) Specifically, how has the Metsco study improved detailed capital planning?

Responses:

a) CPUC refers to section 4.3.1 of the DSP, and to response to 2-Staff-12 and 2-Staff-25 for a description of specific reasons of the variances found in the actual vs planned expenditures.

   CPUC takes steps to improve all its processes in a continuous cycle, including distribution planning processes. For example, CPUC implemented the following changes to improve its distribution planning process in the recent years:
   - CPUC has adopted the methodology of projecting estimated work over a five-years period rather then the historical approach of only planning one year in advance;
   - CPUC's data collection of its assets regarding condition allows CPUC to target those assets that require proactive intervention versus reactive to keep costs low;
   - As CPUC collects additional data points with respect to planned projects and associated costs, CPUC can utilize those data points to further refine its expenditure projection.

b) CPUC is confident that the overall spending will be aligned with the plan presented in the DSP. However, variations are to be expected due to the reasons identified in part (a). CPUC filed all the specific projects within the materiality threshold as prescribed by the OEB Filing Requirements. This represents most of the planned capital. The other projects planned by CPUC do not exceed the materiality threshold. CPUC would like to refer VECC to 2-Staff-31 for updated costs to the capital plan. Additionally, should the capital budget be met, CPUC plans to defer replacing additional assets in a given year should CPUC determine it is safe to do so.

c) Though the study may have not directly improved detailed capital planning, the METSCO study assisted CPUC with identifying a system improvement plan to optimize CPUC's system arrangement to minimize losses, maximize voltage support and to distribute loading evenly. CPUC hired METSCO to provide neutral, external advice and recommendation on the issues CPUC would have liked to address in the future years.

2.0-VECC-5

Reference: DSP, pgs. 99- of 221

Preamble: CPUC explains in its DSP that its current asset assessment relies on entirely on asset age (see page 103) as opposed to tested condition. It is further explained that during this plan cycle it is be populating a new GIS system with data for each asset class.

a) Please explain what targets have been established to implement this asset assessment plan. Specifically, what percentage of each major asset category (poles, transformers etc.) in each year of the plan does CPUC expect to be specifically assessed/tested and entered into its new database?

Responses:

a) CPUC redirects VECC to 2-Staff-22.

2.0-VECC-6

Reference: DSP, pgs. 27, 85- of 221

a) The evidence shows a primary reason for outages in Chapleau is loss of supply. Will the voltage conversion in any manner mitigate loss of supply issues for the Utility?
b) If Chapleau could have Hydro One change one thing to improve reliability of supply to its service territory what would that be? If such a solution has been proposed (as mentioned in Exhibit 2) what cost was suggested that CPUC would need to incur for Hydro One to proceed with the suggested reliability improvement upgrade?

Responses:

a) The voltage conversion will not mitigate loss of supply (LoS) issues as majority of the issues are on the Hydro One system (for additional detail, see 2-Staff-28). Should a LoS occur at the 25kV station affecting CPUC's current in-service 25kV feeder, the affected customers cannot have their service restored until Hydro One addresses the issue. Since CPUC operates at a 4.16kV for its remaining feeders, CPUC does not have the capability to connect the 25kV-feeder to those feeders for switching to reduce the number of customers (or restore power to a percentage if not all customers). However, the voltage conversion can enable a faster restoration of power to a percentage of customers should all feeders be operating at the same voltage level through the use of tie-points and switching capabilities between feeders.

b) HONI has already rectified the issue to improve the reliability related to LoS events with the installation of proper reclosure units. The Loss of Supply outages were on account of Hydro One not having the proper sizing of reclosures on the F4 feeder. This is the same feeder that supplies Chapleau's F1 25kv feeder. What was happening was that whenever a fault occurred down stream of the new reclosures the unit did not isolate the fault as intended. The fault continued to the station opening the station reclosure therefore affecting CPUC 25kv feeder. Since the installation of proper reclosures, CPUC has not experienced LoS events due to the faults occurring from the improper sizing.

   CPUC did not incur any cost for Hydro One to repair the reclosures.

2.0-VECC-7

Reference: DSP, pg. 27

a) Is CPUC aware of any large customers connected directly by Hydro One in the Chapleau area? If yes, please generally describe the Hydro One service territory surrounding the Town.

Responses:

a) The Chapleau General Hospital is directly connected to Hydro One's 25-kV station. The hospital is located on the far west side of the town.

2.0-VECC-8

Reference: Exhibit 2, PDF pg. 18

a) Please provide CPUC's utility fleet (vehicle description and year) in each year 2013 through 2019.

Responses:

a) Table 1 identifies CPUC's utility fleet by year and fleet description for each year. In 2019, CPUC has three units: an RBD in-service since 2018, a service truck in-service since 2015 and a ½ ton in-service since 2012.

Table 1 - CPUC utility fleet

<table>
<tr><th>Date</th><th>RBD/YR</th><th>Service Truck/YR</th><th>½ TON/YR</th></tr>
<tr><td>2013</td><td rowspan="5">In-service since 2002</td><td rowspan="2">In-service since 2007</td><td rowspan="7">In-service since 2012</td></tr>
<tr><td>2014</td></tr>
<tr><td>2015</td><td>Replaced in 2015</td></tr>
<tr><td>2016</td><td rowspan="4">In-service since 2015</td></tr>
<tr><td>2017</td></tr>
<tr><td>2018</td><td rowspan="2">Replaced in 2018</td></tr>
<tr><td>2019</td></tr>
</table>

2.0-VECC-9

Reference: Exhibit 2, DSP, pg. 71 of 221

a) CPUC is proposing conversion from its 4.16kV feeders to 25kv. Is the reason the conversion is not being made to the more common standard of 27.6 kV because of Hydro One's supply?
b) Is CPUC aware of any incremental costs or technical issues in transitioning to 25 kV rather than the more common standard of 27.6 kV?

Responses:

a) CPUC decided to convert the remaining three feeders to 25kV to meet Hydro One's supply voltage. While 27.6kV may seem to be a more common standard for distribution in Ontario, Hydro One's standard in this area is 25kV.

b) CPUC is not aware of any incremental costs or technical issues in transitioning to a 25kV rather than the more common standard of 27.6kV. Benefits of a voltage conversion include:
   - Reduce line losses;
   - Eliminate the Hydro One low voltage tariff;
   - Allow for feeder tie-points between all feeders, specifically to the existing 25kV feeder currently in-service at CPUC that is fed from Hydro One's 25kV station.

   There are additional benefits of converting to 25kV rather than the 27.6kV, which are allowing for conversion of three feeders rather than standardizing to 27.6kV which results in converting the whole system. Additionally, operating at one voltage level instead of two reduces costs of maintaining two sets of asset spares for each system.

2.0-VECC-10

Reference: Exhibit 2, Table 16, pg. 41 of 221

a) Please describe the reasons for the smart meter investments in 2017 and 2018. Over the next five years does CPUC expect similar (or other) significant investments in capital for smart meters?
b) What is the failure rate of the current generation of smart meters in CPUC service territory?

Responses:

a) Smart meter investments were made in 2017 and 2018 for the reverification sample test to extend the service life of smart meters for an additional eight years. The result of the test returned positive – therefore CPUC does not need to replace the smart meters for another eight years. However, minor smart meter investments will be made within the forecast period though not large enough to be considered as a material investment. CPUC has provided the updated costs regarding these smart meter investments as part of 2-Staff-27 and 2-Staff-31.

b) Table 2 consisting of counts of meters that have failed per year.

Table 2 - Meter failure by year

Year	Count
2010	3
2011	4
2012	0
2013	4
2014	6
2015	1
2016	1
2017	0
2018	1

2.0-VECC-11

Reference: Exhibit 2, Table 7, pg. 79 of 221

a) Please explain why CPUC has not established scorecard targets for the cost efficiency and effectiveness of its distribution system plan.

Responses:

a) CPUC did not identify the targets for the cost efficiency and effectiveness of its DSP as they have not yet been identified within the OEB scorecard. CPUC has noted within its DSP the measure has no target yet defined and is currently being explored by CPUC. Exploration of appropriate performance measure implementation is to be completed through LDC benchmarking.

2.0-VECC-12

Reference: Exhibit 2, DSP, Table 16, pg. 91& 147 of 221

Pre-amble: In its DSP CPUC discusses the tradeoff between cost and reduction of scheduled outages when using specialized contracts. The evidence shows that scheduled outages are a significant factor in service reliability of supply.

a) Please explain how much work over the past period of the plan (2012-2018) and the future years (2019-2023) was/will be contracted out. Please explain how CPUC budgets for contracting out as part of its OM&A planning.

Responses:

a) Table 3 highlights the use of contractors at CPUC over the 2012-2023 period. Additionally, contractors are used for station transformer DGA/oil testing on an annual basis, wood pole inspections and IR scans.

These OM&A expenditures are annual and meet the minimum requirements of the DSC. Since CPUC follows the DSC, activities to be contracted out can be identified by CPUC and can accurately budget for these costs for each budget year given the historical actual costs.

Table 3 - Contractor work 2012-2023

Year	Comment
2012	
2013	Contractor installed/rebuilt 2 poles
2014	
2015	Contractor installed/rebuilt 1 pole
2016	Contractor installed/rebuilt 1 pole
2017	
2018	Contractor installed/rebuilt 1 pole
2019-2023	Budgeting for contractor to install 4 poles per year

2.0-VECC-13

Reference: DSP, pgs. 27, 146- of 221

a) Please provide the annual number of poles replaced for each year 2012 through 2023 of the plan.

Responses:

b) Table 4 presents the number of poles replaced over the 2012 to 2018 period. For the 2019-2023 period, based on historical cost and current state of assets, CPUC estimates to replace between 10 to 14 poles annually.

Table 4 - Pole replacement 2012-2018

Year	Count
2012	5
2013	7
2014	6
2015	3
2016	5
2017	9
2018	12

2.0-VECC-14

Reference: 5.4 Appendix D, Metsco Study, pg. 181 of 221

a) Was the Metsco study commissioned in anticipation of a new large load (as implied at the above reference)? If yes, please explain the circumstances and the circumstances as to why that load did not happen.

Responses:

c) No, CPUC did not commission this specific study in anticipation of a new load. The costs of the substation to serve the anticipated load was considered to be too high to be executed within the current timeframe. Therefore, CPUC retained a third-party consultant to provide expertise in recommending alternative solutions to address CPUC's issues and needs in relation to optimizing the system arrangement to minimize losses, maximize voltage support and to distribute loading evenly.

2.0-VECC-15

Reference: DSP, pgs. 27, 85- 195 of 221

Pre-amble: The Metsco study identifies T3 and T4 transformers as being at high risk of failure. CPUC has adopted the Metsco option of enhanced maintenance to address this risk. The study identifies an operation to expend $20-100k on transformer testing and rehabilitation (pg. 195).

a) Please provide the annual maintenance budget for these transformers in the 2018 through 2023 period of the plan.

Responses:

a) Table 5 provides the annual maintenance budget for CPUC transformers. CPUC refers to 2-Staff-31 for the updated total O&M costs. The identified expense of $20-100k on transformer testing and rehabilitation was not part of CPUC's O&M. The activity was oil reclamation completed in 2018 and the expense was capitalized.

Table 5 - Station maintenance cost

Year	2018	2019-2023
Station Maintenance ($)	$4,200	$4,284

2.0-VECC-16

Reference: DSP, pgs. 188

a) The Metsco study contains the following statement:

> *There is a general expectation within Chapleau PUC that operational constraints would be improved if all Chapleau PUC loads were located on the Chapleau PUC transformers. However, this will remain a minor driver.*

Please explain Chapeau's understanding of what this is statement attempting to convey?

Responses:

a) CPUC's understanding of the statement is that it conveys CPUC's preference for all feeders to be supplied by a CPUC-owned station rather than a Hydro One station. This would enable CPUC to operate loads on the current 25kV feeder and reduce outage impacts through the installation of tie points from the existing 25kV feeder to the remaining feeder locations once converted. Additionally, CPUC would prefer to eliminate the low voltage tariff that comes with the operation.

2.0-VECC-17

Reference: DSP, pg. 189 of 221

a) The Metsco study states:

- *a major event in the down town core, such as a fire or significant traffic accident that blocks access for Chapleau PUC crews to repair overhead feeders.*
- *a significant structural problem at the Lisgar Street Bridge that might block access for Chapleau PUC crews.*
- *a significant event or road closure on Hwy 129 preventing crews from restoring power to customers at the end of the feeder.*
- *an equipment fault such as a breaker failure at the Ontario Hydro DS 25kV supply.*

a) Please explain how these concerns are being addressed during the term of the DSP.

Responses:

a) The first three listed concerns from the study are not being addressed by CPUC during the term of the DSP. The identified catastrophic risks are accepted “as is”. The total expenditures that would be required to mitigate those risks are far too high to be taken up by CPUC or the Town of Chapleau. Should the risks be realized in real-life terms, CPUC will actively address the situation at the time with the appropriate response. The fourth identified risk is being partially addressed by CPUC during the term of the DSP. The fault of the equipment at Hydro One 25kV supply can be mitigated by introducing tie-points between CPUC feeders to reduce the customers interrupted or duration during an outage. Introduction of tie-point requires the feeders to operate at one voltage level. Therefore, the CPUC plan to convert three feeders to the existing 25kV level will help to mitigate the faults occurred at Hydro One side.

2.0-VECC-18

Reference: DSP, pg. 189 of 221

a) The Metsco study states:

Accompanying these drivers are secondary drivers that should be considered are

- Feeder Balancing
- Feeder Configuration (backup)
- Phase Balancing

a) Please explain how these concerns are being addressed during the term of the DSP.

Responses:

a) Feeder balancing was addressed by CPUC in 2018 by off-loading the overloaded transformer to the under-utilized transformer. CPUC confirms that it has not experienced feeder balancing.

Feeder configuration concern is limited to 4.16kV feeders only. CPUC doesn't expect any significant load growth at within 4.16kV feeders, therefore, it doesn't plan feeder configurations for the forecast period.
Phase balancing concern is addressed by CPUC on a regular basis. Phase balancing is reviewed and addressed every time a pole is replaced or relocated by picking up the load from another phase for balancing, if required.

Exhibit 3

3-Staff-35

Ref: Exhibit 3, Section 3.1.4

Preamble:

CPUC states that “For degree days, daily observations as reported in Ottawa are used.” Ottawa is approximately 650 km from CPUC.

Question:

a) Why did CPUC use degree days in Ottawa when there are several weather stations closer to its service area?

b) Please update the load forecast using a nearby weather station.

Responses:

a) CPUC confirms that an error was made in drafting the evidence at exhibit 3 at page 9/87 and confirms that its statement at page 19/87, which state “For CPUC, the monthly HDD and CDD as reported in Chapleau were Used” is in fact correct.

b) N/A

3-Staff-36

Ref: Exhibit 3, Section 3.1.5
Exhibit 3, Section 3.1.7

Preamble:

In its Economic Overview in section 3.1.5, CPUC discusses its Location, Climate, and Labour Force. In section 3.1.7, CPUC explained the variables used in the model: HDD, CDD, Customer Number, Days per Month and Spring/Fall.

Question:

a) Did CPUC attempt using economic indicators such as employment and GDP as an explanatory variable in its load forecast model?

   i. If not, please prepare a load forecast which includes employment, and second forecast which includes GDP as scenarios.
   ii. If these variables were tried, why were they discarded?

b) Did CPUC attempt using a trend variable in its load forecast model?

   i. If not, please prepare a load forecast which includes a trend indicator indicating one in the first historical month, increasing by one each month.
   ii. If this variable was tried, why was it discarded?

c) Did CPUC attempt addressing historic actual CDM through an explanatory variable, an adjustment to historic actual or otherwise in its load forecast model?

   i. If not, please prepare a load forecast which includes verified persisting CDM as an indicator.
   ii. If this variable was tried, why was it discarded?

Responses:

a) GDP was not tried but an Employment factor was tried. Any variable that contributes to the reduction in R-Square is discarded.

b) CPUC did not attempt to use a trend variable as it is not a filing requirement to do so. The use of variables is at the discretion of the utility.

c) Similar to CPUC's response to b) CPUC did not attempt to use CDM as a variable in its regression and instead chose to apply the adjustment in a second step. Unfortunately, the scenario that is being asked is not easy to run as CPUC only has yearly CDM adjustments. To get actual monthly CDM savings from its 3rd party CDM coordinator would be time consuming and to estimate monthly CDM savings would not be as accurate as the other monthly variables being used.

3-Staff-37

Ref: Load Forecast Model, sheet Bridge & Test Year Class Forecast

Preamble:

For 2015, 2016, and 2017, the average Unmetered Scattered Load (USL) customer has consumed 723 kWh. Prior to those three years, the average use per customer was over 1000 kWh, and as high as 1,913 kWh in 2011. CPUC has forecasted that for 2018 and 2019, the average use per customer would be equal to the average over the ten years 2008-2017, or 1,308 kWh.

For 2016, and 2017, the average Sentinel customer has consumed less than 900 kWh. Prior to those two years, the average use per customer was over 1000 kWh. CPUC has forecasted that for 2018 and 2019, the average use per customer would be equal to the average over the ten years 2008-2017, or 1,077 kWh.

The street light use per connection has decreased from 894-902 kWh per connection in 2008 - 2011, to 836-837 kWh in 2013-2017.

Questions:

a) Please explain why CPUC decided to use a ten-year average use per customer for these rate classes, when the average use per customer has declined in recent years.

b) If CPUC considers the recent lower usage to be stable, please revise the load forecast to reflect the recent experience.

Responses:

a) CPUC agrees with Board Staff in that using a 10-year average for USL and Sentinel did not take into consideration the declining trend in consumption. CPUC has instead used a 3-year average (2015-2016-2017).

b) CPUC has rerun the forecast accordingly.

3-Staff-38

Ref: Exhibit 3, Table 10
Load Forecast Model, sheet 10yr vs 20yr
Filing Requirements, page 23[7]

Preamble:

The Filing Requirements state that "If monthly Heating Degree Days (HDD) and/or Cooling Degree Days (CDD) are used to determine normal weather, the monthly HDD and CDD based on a) 10-year average and b) a trend based on 20-years. If the applicant proposes an alternative approach, it must be supported."

CPUC has provided a table with 20 years of HDD and CDD. Two columns are provided for "10-year avg" and "20-year avg."

Questions:

a) Please provide the HDD and CDD where a 20-year trend definition is used as opposed to an average.

b) Please confirm that the "10-year avg" column actually calculates a nine-year average.

c) Please revise the "10-year avg" column to calculate a ten-year average.

Responses:

a) See table below:

	10-year avg	20 year avg	Linear trending
HDD			
Jan	1005.2	1016.8	987.3
Feb	915.7	889.6	974.5
Mar	782.0	777.0	801.5
Apr	505.1	490.6	532.6
May	249.5	245.5	247.0
Jun	98.6	102.2	131.9
Jul	48.0	49.1	48.4
Aug	72.4	74.7	73.8
Sep	184.0	181.2	172.1
Oct	399.9	407.5	381.3

[7] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service, July 12, 2018

Nov	603.2	606.6	619.2
Dec	906.5	893.7	909.9
	10-year avg	20 year	Linear trending
		avg	
CDD			
Jan	0.0	0.0	0.0
Feb	0.0	0.0	0.0
Mar	0.0	0.0	0.0
Apr	0.0	0.0	0.0
May	5.1	4.5	5.1
Jun	12.9	18.0	10.7
Jul	32.9	35.7	33.4
Aug	24.4	22.8	24.6
Sep	6.9	7.8	8.2
Oct	0.6	0.3	0.6
Nov	0.0	0.0	0.0
Dec	0.0	0.0	0.0

b) Confirmed

c) See table at a)

3-Staff-39

Ref: Exhibit 3, Table 22
Load Forecast Model, sheet 10yr vs 20yr

Preamble:

CPUC has not allocated any projected CDM to the USL, Sentinel, or Street Lighting rate classes. It has projected 42,041 kWh of CDM savings for the GS > 50 kW rate class, yet this has not resulted in any reduction to billing demand.

Questions:

a) Please confirm that CPUC is not proposing to deliver any CDM programs to these rate classes in 2019.

b) If part a) cannot be confirmed, please update the load forecast with forecasted CDM program savings for the rate classes where CDM programs are expected to be delivered.

c) Please confirm that the CDM programs CPUC is planning for the GS > 50 kW are not expected to deliver any reduction in billing demand.

d) If part c) cannot be confirmed, please update the load forecast with forecasted CDM demand savings for the GS > 50 kW rate class.

Responses:

a) Confirmed

b) N/A

c) CPUC confirms that it anticipates the GS>50 class' demand to be reduced by conservation savings in 2018 and 2019.

d) The Tab "CDM allocation" of the LF model has been updated to reflect a reduction in demand for the GS>50 Class

3-Staff-40

Ref: Chapter 2 Appendices sheet App_2-I LF_CDM
Load Forecast Model sheet CDM Allocation

Preamble:

In Appendix 2-I, CPUC provided the following chart to calculate the 2019 LRAMVA threshold and 2019 CDM manual adjustment to the load forecast.

The composition of the 2019 LRAMVA threshold and CDM adjustment are not consistent. The full year impact of 2017 forecasted savings is included in the LRAMVA threshold, but for the CDM manual adjustment, it shows that 2017 savings were included in the base load forecast.

2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total for 2019
	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Amount used for CDM threshold for LRAMVA (2012)		458,221.00	89,257.00	173,818.00	279,331.00	211,864.00				
Amount used for CDM threshold for LRAMVA (2019)							208,141.00	199,900.00	199,900.00	399,800.00
Manual Adjustment for 2019 Load Forecast (billed basis)	-	-				-	-	199,900.00	99,950.00	299,850.00

Questions:

a) Please confirm that actual 2015 and 2016 CDM savings were embedded in the 2019 load forecast.

b) Has CPUC included a full year of actual 2017 CDM savings in the 2019 load forecast?

i. If yes, please confirm that the 2019 LRAMVA threshold of 399,800 kWh is based on the 199,900 kWh (2018) and 199,900 kWh (2019) forecast savings. If this is correct, please revise the Appendix 2-I chart above to remove the 2017 savings of 208,141 kWh. Please confirm that the associated CDM manual adjustment of 299,850 kWh is correct, as it currently assumes that 2017 savings are actuals in the load forecast.

ii. If not, please clarify whether the 2019 CDM manual adjustment should also include 50% of forecasted 2017 CDM savings. Please confirm the revised 2019 CDM manual adjustment by correcting the Appendix 2-I chart above. For the LRAMVA threshold, please also revise the formula to calculate the LRAMVA threshold based on annualized 2017, 2018 and 2019 savings (totaling 607,941 kWh instead).

c) If there are any revisions based on your response to b) above, please re-calculate the rate class breakdown of the 2019 CDM manual adjustment and 2019 LRAMVA threshold and re-submit an updated rate class allocation in Tab "CDM allocation" of the Load Forecast model to replace Tables 22 and 23 of Exhibit 3 of the Application.

d) As 2015 and 2016 forecast savings are not proposed to be included in the 2019 LRAMVA threshold, please confirm that for the purposes of the LRAMVA calculation going forward, CPUC will not be recovering 2015 and 2016 savings persistence after 2019.

Responses:

a) Confirmed

b) 2017 was not included in the LRAMVA threshold calculations. (CPUC modeled its threshold based on the logic similar to 2018 Board Approved methodologies.

c) The model was updated to remove 2017 from the table. CPUC notes as it did above that it was never included in the total.

d) CPUC cannot confirm this as it intends on including persistence of 2015 and 2016 programs in future years. The logic being that the led lightbulb that was installed in 2015 will continue to generate efficiencies beyond 2019

3-Staff-41

Ref: Chapter 2 Appendix 2-IB

Preamble:

Chapter 2 Appendix 2-IB does not include 2012 approved.

Question:

a) Please prepare an excel worksheet version of Appendix 2-IB which includes 2012 approved.

Responses:

a) Appendix 2-IB only goes back to 2013. Should OEB staff decide to update and provide a revised version of Appendix 2-IB including 2012 and 2012BA, CPUC commits to updating it. Until that time, the 2012 Board Approved vs 2012 Actuals is shown below.

Customers or Connections		
Customer Class Name	**Last Board Appr**	**2012**
Residential	1,133	1,108
General Service < 50 kW	161	162
General Service > 50 to 4999 kW	14	11
Unmetered Scattered Load	6	4
Sentinel	23	23
Street Lighting	341	328
TOTAL	**1,678**	**1,636**
Consumption (kWh)		
Customer Class Name	**Last Board Appr**	**2012**
Residential	14,448,113	13,667,868
General Service < 50 kW	5,209,322	5,015,356
General Service > 50 to 4999 kW	7,592,321	7,148,661
Unmetered Scattered Load	7,209	5,058
Sentinel	25,718	25,594
Street Lighting	292,061	287,471
TOTAL	**27,574,744**	**26,150,008**
Consumption (kW)		

Customer Class Name	Last Board Appr	2012
Residential		
General Service < 50 kW		
General Service > 50 to 4999 kW	19,360	18,736
Unmetered Scattered Load		
Sentinel	65	60
Street Lighting	773	777
TOTAL	**20,198**	**19,573**

3.0-VECC-19

Reference: Exhibit 3, Section 3.1.6
Exhibit 1, Section 1.4.1

a) Section 1.4.1 states: "CPUC's service area is an embedded utility completely contained within the municipal boundaries of the town of Chapleau therefore the utility only serves the community of Chapleau. The area is embedded within the Hydro One Networks Inc." Section 3.1.6 states: "CPUC purchases electricity from Hydro One and embedded generation and IESO as a market participant". Please clarify whether CPUC is fully embedded within and purchases all of its electricity from Hydro One-Distribution or whether it is also purchases electricity through the IESO.
b) Please confirm what is included in the wholesale purchases set out in Table 4.

Responses:

a) CPUC confirms that it purchases its electricity from both Hydro One and the IESO. The sum of both is included in the Wholesale Purchases in the Load Forecast.

3.0-VECC-20

Reference: Exhibit 3, Section 3.1.7

a) What customer classes are included in the “customer count” variable?

Responses:

a) The residential class, GS <50 and GS>50 classes. CPUC should have included a fixed 28 customer for USL (4) and Sentinel (23) and Street Lighting (1). CPUC tested the regression with the additional 28 customers and confirms that it did not affect the results.

3.0-VECC-21

Reference: Exhibit 3, Table 12

a) Are the customer counts set out in Table 12-year end values or average annual values? If average annual values, how was the average calculated?
b) Please provide the 2018 year-end customer count for each customer class.
c) Please explain the customer count adjustment attributed to “MicroFit related consumption”.

Responses:

a) CPUC confirms that it used an average of all 12 months to determine the referred to values.
   - Residential – 1047, GS < 50 – 149, GS>50 – 12, Sentinel – 22 connections, Street Light 328 connections USL - 4

b) CPUC confirms that any reference to Fit/MicroFit was made in error. The utility does not have any Fit/MicroFit.

3.0-VECC-22

Reference: Exhibit 3, Section 3.1.8 – Table 10
Load Forecast Excel Model. Forecast Tab

a) It is noted that, in the Load Forecast Model, the HDD and CDD monthly values used for the 2018 and 2019 forecasts are different. Why is this when the forecast is based on 10 years of historical data?
b) It is noted that the 10-year average of the monthly values for HDD and CDD set out in Table 6 do not match the HDD and CDD monthly values used in the Excel Model to forecast wholesale purchases for either 2018 or 2019. Please explain.

Responses: All three references in the above IR seem to match. See tables comparing both below:

(Excerpt from table 10)

Table 10 - Forecast using a twenty-year weather normalization

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	10 year avg	20 year avg
1114.4	1251.5	1112.5	841.8	973.0	942.2	1123.1	947.6	1086.8	919.1	1003.0	1128.6	1126.9	924.1	850.4	1012.2	1016.8
1008.4	844.1	834.6	925.6	1006.8	966.2	877.3	835.1	880.8	778.9	911.1	949.5	1148.6	975.5	833.9	910.1	889.6
831.3	749.9	827.9	706.9	735.1	889.6	754.9	552.0	828.3	546.2	780.0	972.3	882.7	750.4	863.7	770.1	777.0
579.9	533.5	418.8	415.5	500.7	473.6	491.0	371.5	504.4	475.0	587.3	553.0	506.3	612.0	476.4	508.5	490.6
243.5	305.5	261.7	210.8	215.4	334.4	317.5	186.6	236.9	191.4	277.4	269.4	245.5	257.2	179.1	240.1	245.5
99.6	150.2	50.0	89.8	85.5	86.6	121.1	109.0	96.2	60.2	101.4	71.0	111.0	128.2	101.2	99.9	102.2
47.3	68.5	37.6	31.7	55.4	49.0	82.4	17.2	14.5	25.2	49.8	82.9	48.6	41.0	69.6	47.9	49.1
58.1	129.1	47.2	94.2	77.3	67.9	115.4	52.2	47.7	58.3	66.8	89.1	53.3	37.2	136.1	72.9	74.7
178.2	110.2	135.2	227.7	167.1	214.3	140.3	243.7	178.5	227.0	197.1	212.7	128.7	146.4	151.0	180.6	181.2
438.2	390.8	366.9	463.0	335.6	414.2	479.7	407.8	328.8	410.0	388.9	438.4	442.7	365.9	323.0	398.4	407.5
614.8	570.7	655.8	566.7	668.8	611.0	492.4	583.8	569.7	625.6	663.3	751.5	542.0	504.7	688.2	602.4	606.6
822.4	1005.1	928.8	764.7	910.5	1005.2	920.3	863.7	854.2	854.7	1080.7	867.5	675.3	878.2	1065.3	895.5	893.7
2003.0	2004.0	2005.0	2006.0	2007.0	2008.0	2009.0	2010.0	2011.0	2012.0	2013.0	2014.0	2015.0	2016.0	2017.0	10 year avg	20 year avg
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.8	0.0	11.8	11.5	0.0	0.6	26.1	3.9	12.7	1.1	1.9	0.9	3.4	0.0	5.6	4.5
13.6	3.4	47.1	11.9	36.7	10.0	19.7	3.3	2.1	33.8	9.8	20.9	5.5	16.0	8.3	13.3	18.0
16.0	22.1	59.3	52.6	30.3	10.6	1.8	43.4	62.0	55.5	44.1	10.3	46.9	34.2	20.2	35.4	35.7
27.4	4.2	32.9	14.4	22.5	9.2	20.3	58.0	25.7	22.4	30.8	9.6	22.4	36.7	8.7	26.1	22.8
5.6	17.8	14.6	0.2	6.0	5.6	1.6	0.0	7.7	6.0	0.0	2.0	26.0	3.0	16.8	7.0	7.8
0.0	0.0	0.2	0.0	0.0	0.2	0.0	0.0	5.3	0.0	0.0	0.0	0.0	0.0	0.1	0.6	0.3
																0
																0

(Excerpt from tab Input – Adjustment & Variables)

Variables Used				
HDD	CDD	Ontario cost of electricity	Customer #	D
942.20	0.00	110.50	1336	
966.20	0.00	110.50	1334	
889.60	0.00	110.50	1333	
473.60	0.00	110.50	1335	
334.40	0.00	111.00	1336	
86.60	10.00	111.00	1333	
49.00	10.60	111.00	1337	
67.90	9.20	111.00	1334	
214.30	5.60	111.00	1332	
414.20	0.20	111.00	1333	
611.00	0.00	114.90	1332	
1005.20	0.00	114.90	1330	
1123.10	0.00	114.90	1327	
877.30	0.00	114.90	1326	
754.90	0.00	114.90	1327	
491.00	0.00	114.90	1324	
317.50	0.60	120.10	1326	
121.10	19.70	120.10	1323	
82.40	1.80	120.10	1324	
115.40	20.30	120.10	1325	
140.30	1.60	120.10	1322	
479.70	0.00	120.10	1324	
492.40	0.00	119.30	1322	
920.30	0.00	119.30	1320	
947.60	0.00	119.30	1317	
835.10	0.00	119.30	1316	
552.00	0.00	119.30	1312	
371.50	0.00	119.30	1315	
186.60	26.10	130.90	1309	
109.00	3.30	130.90	1310	
17.20	43.40	140.90	1308	
52.20	58.00	140.90	1306	
243.70	0.00	140.90	1307	
407.80	0.00	140.90	1305	
583.80	0.00	136.80	1307	
863.70	0.00	136.80	1306	
1086.80	0.00	131.70	1307	

(Excerpt Table 6 of Ex 3)

Table 5 - HDD and CDD as reported at Utility Location

HDD	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
January	942.20	1123.10	947.60	1086.80	919.10	1003.00	1128.60	1126.90	924.10	850.40
February	966.20	877.30	835.10	880.80	778.90	911.10	949.50	1148.60	975.50	833.90
March	889.60	754.90	552.00	828.30	546.20	780.00	972.30	882.70	750.40	863.70
April	473.60	491.00	371.50	504.40	475.00	587.30	553.00	506.30	612.00	476.40
May	334.40	317.50	186.60	236.90	191.40	277.40	269.40	245.50	257.20	179.10
June	86.60	121.10	109.00	96.20	60.20	101.40	71.00	111.00	128.20	101.20
July	49.00	82.40	17.20	14.50	25.20	49.80	82.90	48.60	41.00	69.60
August	67.90	115.40	52.20	47.70	58.30	66.80	89.10	53.30	37.20	136.10
September	214.30	140.30	243.70	178.50	227.00	197.10	212.70	128.70	146.40	151.00
October	414.20	479.70	407.80	328.80	410.00	388.90	438.40	442.70	365.90	323.00
November	611.00	492.40	583.80	569.70	625.60	663.30	751.50	542.00	504.70	688.20
December	1005.20	920.30	863.70	854.20	854.70	1080.70	867.50	675.30	878.20	1065.30
Total	6054.20	5915.40	5170.20	5626.80	5171.60	6106.80	6385.90	5911.60	5620.80	5737.90

3.0-VECC-23

Reference: Exhibit 3, Section 3.2.1

a) Please confirm that the 2015-2020 CDM Plan filed with the Application is CPUC's most recently approved CDM Plan. If not confirmed, please provide CPUC's most recently approved 2015-2020 CDM Plan.

Responses:

a) CPUC confirms that the 2015-2020 CDM plan filed with the application is the most recent approved CDM Plan.

3.0-VECC-24

Reference: Exhibit 3, Table 37
Exhibit 8, Section 8.1.5

a) Please provide a revised version of Table 37 that includes a column with the actual values for 2018.
b) Please explain the 2018 forecast gain on disposition (USoA 4355). Did this actually occur?

Responses:

a) Please see the table below:

	Reporting Basis	CGAAP	CGAAP	CGAAP	CBAAP	CGAAP	CGAAP
		2012	2015	2016	2017	2018	2019
	USoA Description	**Board Approved**					
4235	**4235-Miscellaneous Service Revenues**	$0	-$7,995	-$5,580	-$9,731	-$7,272	-$6,207
4225	**4225-Late Payment Charges**	$0	-$6,480	-$5,782	-$5,682	-$5,115	-$5,355
4082	4082-Retail Services Revenues	$0	-$2,706	-$3,090	-$2,749	-$2,723	-$2,632
4084	4084-Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0
4086	4086-SSS Administration Revenue	$0	$0	$0	$0	-$4,643	-$4,736
4205	4205-Interdepartmental Rents	$0	$0	$0	$0	$0	$0
4210	4210-Rent from Electric Property	$0	-$13,519	-$13,519	-$13,609	-$13,609	-$13,719
4215	4215-Other Utility Operating Income	$0	$0	$0	$0	$0	$0
4220	4220-Other Electric Revenues	$0	$0	$0	$0	$0	$0
4240	4240-Provision for Rate Refunds	$0	$0	$0	$0	$0	$0
4245	4245-Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0
4305	4305-Regulatory Debits	$0	$45,468	$0	$0	$0	$0
4310	4310-Regulatory Credits	$0	$0	$0	$0	$0	$0
4315	4315-Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0
4320	4320-Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0
4324	4324-Special Purpose Charge Recovery	$0	$0	$0	$0	$0	$0
4325	4325-Revenues from Merchandise Jobbing, Etc.	$0	-$825	-$18,559	-$15	$0	$0
4330	4330-Costs and Expenses of Merchandising Jobbing, Etc.	$0	-$1,320	-$1,496	$0	$0	$0
4335	4335-Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0
4340	4340-Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0
4345	4345-Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0
4350	4350-Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0
4355	4355-Gain on Disposition of Utility and Other Property	$0	$0	$0	$0	-$50,000	$0
4360	4360-Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0
4365	4365-Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0
4370	4370-Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0
4375	4375-Revenues from Non-Utility Operations	$0	$0	$0	-$16,952	-$150,107	-$39,474
4375	4375-Sub-account Generation Facility Revenues	$0	$0	$0	$0	$0	$0
4380	4380-Expenses of Non-Utility Operations	$0	$0	$0	$18,360	$127,141	$25,658
4380	4380-Sub-account Generation Facility Expenses	$0	$0	$1,152	$0	$0	$0
4385	4385-Non-Utility Rental Income	$0	$0	$0	$0	$0	$0
4390	4390-Miscellaneous Non-Operating Income	$0	$0	$0	$0	$0	$0

4395	4395-Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0
4398	4398-Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0
4405	4405-Interest and Dividend Income	$0	-$13,641	-$3,650	-$9,313	-$10,305	-$9,000
4415	4415-Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0
other	other	$0	$0	$0	$0	$0	$0
other	other	$0	$0	$0	$0	$0	$0
	Total	-$6,000	-$38,058	-$38,058	-$1,018	-$50,523	-$55,464

	Specific Service Charges	$0	-$7,995	-$5,580	-$9,731	-$7,272	-$6,207
	Late Payment Charges	$0	-$6,480	-$5,782	-$5,682	-$5,115	-$5,355
	Other Distribution/Operating Revenues	$0	-$16,225	-$16,609	-$16,357	-$20,975	-$21,087
	Other Income or Deductions	$0	$29,681	-$22,552	-$7,920	-$83,271	-$22,816
	Total	$0	-$1,018	-$50,523	-$39,691	-$116,632	-$55,464

b) The gains on disposal in 4355 is related to the sale of the old bucket truck for an amount of $50k.

3.0-VECC-25

Reference: Exhibit 3, Sections 3.4.1 and 3.4.3
Exhibit 8, Sections 8.1.5 and 8.1.9

a) At Section 3.4.1 the Application states that CPUC is proposing one change to the MicroFit Service Charge. Sections 8.1.5 and 8.1.9 also indicate there is a change to the MicroFit Service Charge. However, in Section 3.4.3, the Application states that CPUC is not proposing any changes to the MicroFit Service Charge. Please reconcile.

Responses:

a) This was an error in the drafting of the evidence. CPUC does not have any Fit and MicroFit, therefore, any reference to MicroFit charges should be ignored.

3.0-VECC-26

Reference: Exhibit 3, Section 3.4.1
Exhibit 8, Section 8.1.10

a) Has CPUC been charging the revised Specific Charge for Access to Power Poles since September 2018? If so, what is the balance in the associated variance account as of December 31, 2018, and in which variance/deferral account is it recorded?

Responses:

a) The balance is in account 1508 – Pole Attachment Revenue Variance, with a credit balance of 1,116.58.

Exhibit 4

4-Staff-42

Ref: Exhibit 4, page 20, 21
Exhibit 4, page 23, 24

Preamble:

At the above noted first reference, CPUC indicated the following, regarding Account 5665, Miscellaneous General Expense.

> In working on the variances analysis, it came to CPUCs attention that this account has been used as a catch all for adjustments recommended by the utility's accounting firm (KPMG) post year-end. While CPUC understands and accepts accounting policy choices are the decision of management, and thus, CPUC takes responsibility for errors in journal entries, it does rely and trust the expertise of its accounting firm. For the sake of transparencies, CPUC highlights the following adjustments since 2012.

At the above noted first reference, CPUC highlighted the following adjustments.

1. 2016: KPMG entry - to adjust RSVA power accounts to actual: $14,420.38
2. 2016: KPMG entry - to adjust acc't to actual (other acc't affected was 3045 Unappropriated Retained Earnings): $26,308
3. 2015: KPMG entry - to adjust the revenue adjustment acc't: $34,636.96
4. 2015: KPMG entry - To reduce HST/OVAT acc'ts: $4,113.84
5. 2014: KPMG entry - to adjust energy sales acc'ts to actual (with change in billing periods re: unbilled revenue): $ 90,339.40
6. 2013: KPMG entry - To write off prior year O/S cheques: $659.51

OEB staff notes that some of these adjustments are immaterial.

At the above noted second reference, CPUC indicated the following regarding Account 5665, Miscellaneous General Expense.

> The total OM&A costs in 2014 were considerably higher than the 2013 Actuals. The major component of the increase was an adjustment made at the recommendation of KPMG. This one time entry to account 5665 was to adjust for the change in CPUC's billing cycle changing from the 15th to the 1st of the month. The rationale for the adjustment was to account to adjust unbilled revenue because unbilled revenue in 2014 was much less as compared to 2013…

Questions:

a) Regarding the material adjustments above and other interrelated adjustments, please confirm that there is no impact on CPUC's deferral and variance account balances from incorrectly flowing these adjustments through Account 5665, rather than the correct accounts (e.g. cost of power revenue Account 4006 through Account 4075, cost of power expense Account 4705 through Account 4750). Please explain.

b) If there is an impact on CPUC's deferral and variance account balances, please quantify the impact on the respective deferral and variance account balance. Please explain.

Responses:

a) There is no impact to the deferral and variance accounts as the correct balances were included within the revenue and expense accounts. As of the period end date, there were items which were included within balance sheet accounts which were required to be adjusted to the income statement. To ensure the appropriate amounts were included within the revenue and cost of sales accounts along with the related variance accounts it was determined the adjustments needed to flow through operating expenses.

While the use of the account #5665 should not have been utilized given the focus of the OEB on this account, these amounts were required to be expensed in the fiscal years noted above and therefore were appropriately included within operating expenses and resulting net income in that period. The entries noted above were combined entries which impacted a number of year-end adjustments and accounts.

Going forward, any adjustments required to balance sheet accounts as of the period end date will not be posted within account #5665 to ensure this account is utilized only for reasons specified by the OEB (which are anticipated to be minimal).

This can be seen within the 2017, and the draft 2018 adjustments to date where there are no adjustments flowed through this account.

b) There is no impact noted to the RSVA variance accounts. The adjustments included in account #5665 should flow to other operating expense accounts (rather than #5665).

4-Staff-43

Ref: Decision and Order, November 29, 2012[8]

Preamble:

OEB staff notes that in its 2012 cost of service proceeding,[9] CPUC submitted that it does not allocate supervision costs and labour to capital projects.

As per CPUC's 2012 cost of service proceeding, the following item was noted by the OEB in its decision and order issued on November 29, 2012, related to compensation costs:

- Page 15 – The OEB stated that it expects that the degree by which the costs for compensation are capitalized will be examined when CPUC transitions to IFRS.

Question:

a) Please explain how CPUC has addressed the above-noted OEB concern articulated in its 2012 cost of service proceeding decision. Please describe the steps CPUC undertook to ensure that its capitalization policies are in compliance with IFRS. Please also confirm that these policies are in compliance with IFRS.

Responses: Response provided by KPMG

Before the transition to IFRS, CPUC had documented the information relating to the allocation of burdens as well as at the allocation of certain costs to the cost of PPE. The accounting policy decision made is as follows:

Directly Attributable:

The following provides general guidelines as to which expenditures can be considered directly attributable and therefore eligible for capitalization:

"Directly Attributable" expenses include:

- Employee costs and benefits incurred by employees working directly on construction or acquisition of assets (IAS 16.17(a))
- Costs of site preparation
- Initial delivery and assembly
- Testing costs (less any incremental income earned during the testing phase)
- Professional fees

Per IAS 19.4, Employee Benefits includes:

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[8] EB-2011-0322

[9] EB-2011-0322

a) short term employee benefits (wages, social security), paid sick leave, profit sharing, bonuses and non-monetary benefits (medical care, cars, subsidized services) for current employees
b) post-employment benefits such as pensions, other retirement benefits, post-employment life insurance, and post-employment medical care
c) other long-term employee benefits, including long-service leave, LTD, and
d) termination benefits

It does NOT include:

- Administrative and other general overhead costs (IAS 16.19(a))
- Feasibility studies (IAS 16.17(a))
- Startup or pre-opening costs (i.e., costs incurred prior to the approval of a specific project are not related to a *specific* item of PP&E) (IAS 16.19)
- Training costs (IAS 16.19(c))
- Abnormal waste (IAS 16.22)
- Costs incurred when construction is interrupted unless certain criteria are met (IAS 16.23)
- Costs of opening a new facility (IAS 16.19(a))
- Relocation costs (IAS 16.20(b))

4-Staff-44

Ref: Exhibit 4, page 7, Table 2 - Total OM&A
Exhibit 4, page 8
Exhibit 4, page 30

Preamble:

At the first above noted reference, OEB staff notes that CPUC has requested 2019 test year OM&A of $821,163. This represents a 22.5% increase over 2012 actual, or 3.2% per year, and a 27.4% increase over 2012 OEB approved, or 3.9% per year.

At the second above noted reference, CPUC stated the following:

> The CPI rate is a measure that can fluctuate significantly from quarter to quarter. Using the most recent rate does not always reflect the historical trends nor predicted trends; therefore CPUC typically uses the flat rate of 2% of inflation for budgeting purposes. The Bank of Canada aims to keep inflation at the 2% midpoint of an inflation-control target range of 1% to 3% and recently reported CPI median of 2%. Therefore, the utility deems it appropriate to use 2% as an inflation rate.

However, at the above noted third reference, CPUC stated that as of 2018, CPUC plans on using the adjusted price cap index as an inflation factor.

Question:

a) Please identify what improvements in services and outcomes CPUC's customers will experience in 2019 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2019, annually at higher rate than:

   i. the rate of inflation which is approximately 1.5%[10]

   ii. the rate of 2.0% which CPUC states it uses for budgeting purposes in the past and effective January 1, 2018 CPUC used the adjusted price cap index as an inflation factor of 0.75%[11]

Responses:

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[10] 2019 EDR Webpage November 23, 2018 Reference – "…the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2019, to be 1.5%..."

[11] An adjusted price cap index of 0.75% (i.e. the OEB's 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)

a) Not all costs incurred by a utility are fixed, predictable or subject to inflationary increases and therefore solely using the inflation as a reason for an OM&A increase may not always reflect a utility's reality. Some of a utility's costs cannot be predicted i.e. DSP, OEB audits, training, increase in O&M due to unpredictable weather. As explained in detail in Exhibit 4, the increase from 2012 to 2019 is attributable to various factors. To assume that the utility will not be subject to similar factors from 2019-2024 is not particularly realistic.

b) Through the exercise of putting together the cost of service application, CPUC has gained a better understanding of how the PriceCap index is adjusted to reflect the PEG efficiency ranking. As such, CPUC commits to doing its best to keep its costs which are susceptible to inflation within the range of its adjusted PriceCap index and commits to keep exploring options that would help reduce costs and increase efficiencies.

4-Staff-45

Ref: Exhibit 4, page 7, Table 2 - Total OM&A
Load Forecast Model – CPUC 2019 TESI Load ForecastingNM 201800831.xls, tab Final LF
Exhibit 4, Table 4 – OEB Appendix 2-JB – Recoverable OM&A Cost Driver Table
Excel Appendix 2-JB

Preamble:

At the above noted first reference, the following was shown:

- That the 2012 OEB approved level of OM&A was $644,340, while the actual OM&A costs were $670,607, a difference of $26,267, or 4.1% percent higher than the anticipated level

- A 2019 test year requested OM&A of $821,163, which is $176,823, or 27.4% higher than the 2012 OEB approved level of OM&A, and $150,556 or 22.5% higher than 2012 actual

At the second above noted reference, the Load Forecast model, Final LF tab, shows an increase in 2019 test year kWh and kW, versus 2012 actual, of approximately 25,000 kWh or 0.1% and 149 kW or 0.8%.

At the third above noted reference, Table 4 shows a high level description of the changes between 2012 OEB-approved OM&A and 2019 test year OM&A. CPUC has provided more detail at Exhibit 4, Pages 14-21.

1 **Table 4 – OEB Appendix 2-JB – Recoverable OM&A Cost Driver Table**[6]

Reporting Basis	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A	2012	2013	2014	2015	2016	2017	2018	2019
OM&A Cost Drivers >$10,000	$538,994.71	$670,607.00	$638,471.00	$744,673.00	$730,565.00	$744,037.00	$716,586.00	$809,404.00
Operation								
5020-Overhead Distribution Lines & Feeders - Operation Labour	$0		$13,425			-$15,186	$14,393	
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	$19,069	-$14,106		$22,237	$10,150		
5065-Meter Expense	$0	-$90,957						
Billing and Collecting								
5310-Meter Reading Expense	$0	$12,578						
5335-Bad Debt Expense	$0		$23,102	-$10,871	-$12,137			
Administration								
5610-Management Salaries and Expenses	$0				$27,080	$21,847	39,378	
5630-Outside Services Employed	$0	-$18,883	$0	$61,550	-$33,890	-$11,678	-26,046	
5635-Property Insurance	$0				-$10,495			
5645-Employee Pensions and Benefits	$0					$10,536	$10,158	
5655-Regulatory Expenses	$0	$12,024	-$11,584				$33,581	$21,522
5665-Miscellaneous General Expenses	$0		$94,880	-$56,604		-$44,485		
Misc <1000	$131,612							
Misc <5000	$0	$34,031	$484	-$8,184	$20,677	$1,364	$21,354	-$9,763
Closing Balance	$670,607	$638,471	$744,673	$730,565	$744,037	$716,586	$809,404	$821,163

Questions:

a) Please state and explain whether the overstatement of CPUC's 2012 OEB approved level of OM&A of $670,607, versus actual 2012 OM&A costs of $644,340, a difference of $26,267, or 4.1% percent higher, raises concerns about the accuracy of CPUC's current 2019 test year forecast. If this is not the case, please explain.

b) Please explain the increase in OM&A in the 2019 test year versus 2012, considering the load forecast in both kWh and kW is expected to increase by a negligible amount over the same period (i.e. 0.1% increase in kWh and 0.8% increase in kW.) If this is not the case, please explain.

c) The 2013 column in the Excel Appendix 2-JB is hidden. When updating Appendix 2-JB please unhide the 2013 column.

d) It is unclear whether the 2012 column in both the Excel Appendix 2-JB and the PDF Exhibit 4 Appendix 2-JB is 2012 OEB approved or 2012 actual. Please update the Excel and PDF versions of Appendix 2-JB to show both 2012 OEB approved and 2012 actual columns.

Responses:

a) The year over year variances between 2012 Board Approved and 2012 Actuals were explained in detail at Exhibit 4.

- Variances in Account 5020 were explained at page 14/201
- Variances in Account 5025 were explained at page 15/201
- Variances in Account 5065 were explained at page 16/201
- Variances in Account 5315 were explained at page 16/201
- Variances in Account 5630 were explained at page 17/201

b) CPUC disagrees with the premise of the question, that an increase in cost is solely relative to an increase in customers or consumption. CPUC notes that many events and procedures implemented over the past 7 years have been mandated by the OEB and have little to nothing to do with customer count or consumption. i.e., DSP, bi-monthly billing to monthly billing, increase in filing requirements and RRR filing, winter disconnect ban, OEB audits, etc. The evidence in Exhibit 4 explains and justifies in detail the year over year increases in OM&A.

c) Please note that this is an issue with the OEB model and has been an issue for over 5 years now. A macro in the background of the model hides 2013 as the model is opened.

Appendix 2-JB

Recoverable OM&A Cost Driver Table[1,3]

Reporting Basis	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A	**2012 BA**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
OM&A Cost Drivers >$10,000	$584,481.00	$538,994.71	$670,607.00	$638,471.00	$744,673.00	$730,565.00	$744,037.00	$716,586.00	$809,404.00
Operation									
5020-Overhead Distribution Lines and Feeders – Operation Labour		$0		$13,425			-$15,186	$14,393	$0
5025-Overhead Distribution Lines and Feeders – Operation Supplies and Expenses	-$4,483	$0	$19,069	-$14,106		$22,237	$10,150		
5065-Meter Expense		$0	-$90,957						
Billing and Collecting									
5310-Meter Reading Expense	$27,224	$0	$12,578						
5335-Bad Debt Expense		$0		$23,102	-$10,871	-$12,137			
Administration									
5610-Management Salaries and Expenses		$0				$27,080	$21,847	39,378	
5630-Outside Services Employed	$45,722	$0	-$18,883	$0	$61,550	-$33,890	-$11,678	- 26,046	
5635-Property Insurance		$0				-$10,495			
5645-Employee Pensions and Benefits		$0					$10,536	$10,158	
5655-Regulatory Expenses	$6,654	$0	$12,024	-$11,584				$33,581	$21,522
5665-Miscellaneous General Expenses		$0		$94,880	-$56,604		-$44,485		
Misc. <1000		$131,612							
Misc. <5000	$4,892	$0	$34,031	$484	-$8,184	$20,677	$1,364	$21,354	-$9,763
Closing Balance	$664,490	$670,607	$638,471	$744,673	$730,565	$744,037	$716,586	$809,404	$821,163

4-Staff-46

Ref: Excel Appendix 2-JC
Exhibit 4, Table 17 - OEB Appendix 2-JC – OM&A Programs Table

Preamble:

OEB staff notes that both the Excel and PDF Appendix 2-JC has only one column for 2012 and does not specify whether it is 2012 OEB approved or 2012 actual.

Question:

a) Please update the evidence to show 2012 OEB approved and 2012 actual.

Responses:

a) Please find the requested table below. The OM&A program did not exist in 2012; therefore, the table below is for illustrative purposes only.

OM&A Program Table

Reporting Basis	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Programs	**2012BA**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Customer Focus									
Customer Service, Mailing Costs, Billing and Collections, LEAP	$52,200.00	$69,560.05	$74,219.95	$75,286.41	$78,150.35	$79,342.15	$80,816.11	$88,000.00	$87,690.00
Bad Debts	$3,600.00	$4,107.05	$6,668.99	$29,771.17	$18,900.41	$6,763.22	-$208.49	$5,000.00	$5,000.00
Meter Reading	$29,000.00	$22,033.32	$34,611.56	$30,966.66	$32,959.16	$35,466.49	$41,027.29	$42,000.00	$41,040.00
Operational focus	$73,200.00	$61,236.70	$70,350.86	$163,080.53	$112,540.55	$99,035.53	$51,989.04	$59,980.00	$56,190.00
Sub-Total	**$158,000.00**	**$156,937.12**	**$185,851.36**	**$299,104.77**	**$242,550.47**	**$220,607.39**	**$173,623.95**	**$194,980.00**	**$189,920.00**
Operational and Administrative Effectiveness									
Municipal Transformer Station -operating and maintenance costs	$5,700.00	$4,023.95	$2,493.59	$3,390.12	$3,467.60	$2,991.14	$2,080.44	$4,200.00	$4,284.00
Meters maintenance	$600.00	$92,076.41	$1,119.90	$1,675.40	$572.37	$514.32	$7,009.77	$6,800.00	$6,936.00
Overhead lines	$199,140.00	$193,610.74	$216,798.52	$218,145.02	$204,199.34	$232,826.63	$228,818.85	$236,400.00	$233,150.00
Outside Services (Accounting)	$106,400.00	$58,598.09	$39,715.18	$49,125.20	$110,675.31	$76,785.06	$65,107.08	$39,061.00	$30,061.00
Wages Executive & Management, Benefits, Pension, Injuries & Damages	$157,980.00	$156,575.41	$171,682.99	$164,006.95	$159,325.52	$199,378.26	$229,553.72	$283,990.00	$291,317.00
Sub-Total	**$469,820.00**	**$504,884.60**	**$431,810.18**	**$436,342.69**	**$478,240.14**	**$512,495.41**	**$532,569.86**	**$570,451.00**	**$565,748.00**
Public and Regulatory Responsiveness									
Regulatory & Compliance	$14,520.00	$6,785.20	$18,809.32	$7,225.81	$7,774.19	$8,933.79	$8,392.02	$41,973.00	$63,495.00
Sub-Total	**$14,520.00**	**$6,785.20**	**$18,809.32**	**$7,225.81**	**$7,774.19**	**$8,933.79**	**$8,392.02**	**$41,973.00**	**$63,495.00**
Miscellaneous									
Donation Leap	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00
Sub-Total	**$2,000.00**	**$2,000.00**	**$2,000.00**	**$2,000.00**	**$2,000.00**	**$2,000.00**	**$2,000.00**	**$2,000.00**	**$2,000.00**

4-Staff-47

Ref: Exhibit 4, page 7 & 8
OEB Letter April 15, 2015, Notice of Amendment to a Code, Amendments to the Distribution System Code[12]

Preamble:

At the above noted first reference, CPUC stated the following:

> The total cost increased from 2013 to 2014, when our rates came into effect and remained fairly stable until 2018 when total rates went up by 13%. The increase can be attributed to two major drivers that impacted both the utility's overall costs. The first driver was the change in organizational structure from a virtual utility to a conventional utility which caused an increase in overall staffing costs. The methodology used to allocate corporate cost allocations was based on a one-way percentage which upon further analysis revealed that the utility had been benefiting from cost sharing opportunities with its affiliate at the detriment of the affiliate which ended up shutting its operations and doors on December 31, of 2017.
>
> The second driver is related to changes in the managerial staffing. Up until 2016, CPUC operated with a Manager who supervised both the operations and administrative functions. The Secretary-Treasurer in question retired in 2016 and has since then been replaced by two managerial staff, 1) a former senior linesperson, now General Manager who oversees the operations and 2) a Manager of Finance who oversees the administrative side of the utility such as regulatory, accounts management, payroll, and all other administrative functions.
>
> Billing and Collecting shows an increase of $50K which most of the increase can be attributed to going from bi-monthly to monthly billing. Regular costs related to billing are also subject to inflationary increases such as services, paper, stamps, and salaries.

At the above noted second reference, OEB staff notes that the transition to monthly billing was referenced in the OEB's letter of April 15, 2015, regarding Amendments to the Distribution System Code.[13] The OEB stated that with respect to the costs associated with the transition to monthly billing, distributors could apply for a deferral account with evidence demonstrating that such an account would meet the eligibility requirements.

Questions:

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[12] EB-2014-0198
[13] EB-2014-0198

a) Please explain the increase in billing and collecting expenses of $50k, even considering the move from bi-monthly billing to monthly billing.

b) Please explain the increase of $50k in OM&A from 2012 to 2019 for billing and collecting expenses, considering CPUC had other options in the past (e.g. an application for a deferral account) which may have helped to financially ease its transition to monthly billing.

Responses:

a) The cost of Sensus Canada to do the hourly meter reads increased 20k per year from 2012. The other major factor is the cost allocation between ESC and PUC. In 2012 PUC was paying 83.19% of the cost whereas now it’s 100%.

b) Unfortunately, CPUC staff cannot answer or explain a managerial decision that was made by a previous manager which no longer works at the utility. That said, in preparing the application, CPUC’s current management never saw any indication that the utility was in financial distress as a result of the change in policy. Nowhere in the application did CPUC state that going to monthly billing required the need for the use of a deferral and variance account. The utility does, however, believe that it should, like every other utility in the province, be able to recover through rates additional costs resulting from an OEB mandated policy which forced utilities to go to monthly billing.

4-Staff-48

Ref: Exhibit 4, Table 18 - OEB Appendix 2-K – Employee Compensation
Exhibit 4, Table 22 - Headcount (number of months worked per year)
Exhibit 4, page 8
Exhibit 4, page 8
Exhibit 4, page 30
Exhibit 4, page 43-44
Exhibit 4, page 9

Preamble:

At the above noted first reference, the following table is shown:

1 **Table 18 - OEB Appendix 2-K – Employee Compensation**[13]

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	1	1	1	1	2	2	2	2
Non-Management (union and non-union)	4	4	4	4	3	3	5	3
Total	5	5	5	5	5	5	7	5
Total Salary and Wages including overtime & incentive pay								
Management (including executive)	$59,567	$64,246	$60,027	$60,695	$87,775	$109,622	$149,000	$149,760
Non-Management (union and non-union)	$190,803	$197,902	$213,139	$202,384	$208,649	$190,688	$218,550	$212,764
Total	**$250,370**	**$262,148**	**$273,166**	**$263,078**	**$296,424**	**$300,309**	**$367,550**	**$362,524**
Total Benefits (Current + Accrued) -								
Management (including executive)	$2,925	$3,132	$3,216	$3,039	$5,924	$5,123	$11,302	$11,555
Non-Management (union and non-union)	$10,793	$11,172	$11,784	$11,419	$11,740	$9,343	$6,638	$6,642
Total	**$13,718**	**$14,304**	**$15,000**	**$14,457**	**$17,664**	**$14,465**	**$17,940**	**$18,197**
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$62,493	$67,378	$63,243	$63,733	$93,699	$114,744	$160,302	$161,315
Non-Management (union and non-union)	$201,596	$209,074	$224,923	$213,802	$220,389	$200,030	$225,188	$219,406
Total	**$264,088**	**$276,452**	**$288,166**	**$277,536**	**$314,088**	**$314,775**	**$385,490**	**$380,721**
Integrity Check from accounts 5020/5610/5615	$233,829	$244,225	$254,128	$246,457	$283,582	$287,044		
Wages posted to 5315	$30,259	$32,227	$34,038	$31,078	$30,506	$27,731		
Difference	$0	$0	$0	$0	$0	$0		

At the above noted second reference, Table 22 - Headcount (number of months worked per year), show a 2018 number of FTEs of five.

At the third above noted reference, CPUC stated the following:

> The CPI rate is a measure that can fluctuate significantly from quarter to quarter. Using the most recent rate does not always reflect the historical trends nor predicted trends; therefore CPUC typically uses the flat rate of 2% of inflation for budgeting purposes. The Bank of Canada aims to keep inflation at the 2% midpoint of an inflation-control target range of 1% to 3% and recently reported CPI median of 2%. Therefore, the utility deems it appropriate to use 2% as an inflation rate.

CPUC has proposed no increase in FTEs for 2019 (5 FTEs), compared to 2012 (5 FTEs). However, as per Table 18, the following increases in compensation over this time period have occurred:

- Total Salary and Wages (including overtime and incentive pay) has increased by $112,154, or 44.8% (6.4% per year)
- Total Benefits has increased by $4,479, or 32.7% (4.7% per year)
- Total Compensation has increased by $116,633, or 44.2% (6.3% per year)

OEB staff notes that the inflation rate is 1.5%.[14] At the above noted fourth reference, CPUC also stated that it uses an inflation rate of 2.0% for budgeting purposes. However, at the above noted fifth reference, CPUC stated that as of 2018, CPUC plans on using the adjusted price cap index as an inflation factor.

At the sixth above noted reference, CPUC stated the following:

> CPUC confirms that its staffing and compensation strategy has not changed significantly since its last Cost of Service but that the composition of its workforce has changed partly due to unforeseen events, and as a result of the retirement of the Secretary-Treasurer in 2016 whose role and function was distributed across the new General Manager and the new Manager of Finance.
>
> Concerning succession planning, CPUC is of the mind that finding qualified staff in smaller rural areas can be challenging. Therefore, similar to other smaller utilities, CPUC prefers to invest time and energy in training its existing employees rather than hiring workers that are already trained. CPUC's view is that the risks associated with hiring are mitigated because the employer already knows the employee and has experience with the employee's work ethic, ability to work with others and problem-solving skills. The learning curve is also cut down because its existing employees understand the utility and energy sector.
>
> In doing so, CPUC must also balance reliance on third-party contractors, and use its workforce to its best advantage for the customer and community. The utility evaluates on a yearly basis its agreements with its consultants and contractors to ensure that they are the best option possible for the utility.
>
> CPUC did not use specific benchmarking studies to determine salary ranges other than basing its inflation rate and salary at the Town of Chapleau.

At the seventh above noted reference, CPUC stated the following:

> CPUC employees including Powerline Maintainer are non-unionized employees. (ref: Section 4.4). All non-unionized employees are adjusted on a yearly basis to reflect the inflation factor (ref: Section 4.2.3).

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[14] 2019 EDR Webpage November 23, 2018 Reference – "…the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2019, to be 1.5%..."

Questions:

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

b) Please confirm that effective January 1, 2018 CPUC used the adjusted price cap index of 0.75% as an inflation factor for budgeting purposes.[15] If this was not the case, please explain.

c) Please explain the increased total compensation costs of $116,633, or 44.2% (6.3% per year), when comparing 2019 test year to 2012, or approximately 6.3% per year:

   i. when inflation is approximately 1.5%

   ii. in the past CPUC used an inflation rate of 2.0% for budgeting purposes and effective January 1, 2018 CPUC used the adjusted price cap index as an inflation factor[16]

   iii. Reconciling to the description of changes to FTEs provided in Exhibit 4, Table 18:

      a. the number of management 2019 FTEs has increased to two FTEs, versus one FTE in 2012
      b. the number of non-management 2019 FTEs has decreased to three FTEs, versus four FTEs in 2012
      c. the number of total 2019 FTEs has stayed the same at five FTEs, versus the number of FTEs in 2012

d) Please explain why at the above noted second reference, Table 22 - Headcount (number of months worked per year), a 2018 number of FTEs of five is shown, whereas in the first above noted reference, Table 18 - OEB Appendix 2-K – Employee Compensation a 2018 number of FTEs of seven is shown.

e) Please explain why CPUC shows FTEs in Appendix 2-K for the period 2012 to December 31, 2017 when it operated as a “virtual” utility during this time. (i.e. in the past, employees were employed by its affiliate, Chapleau Energy Services

[15] An adjusted price cap index of 0.75% (i.e. the OEB’s 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)
[16] An adjusted price cap index of 0.75% (i.e. the OEB’s 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)

(CES), instead of CPUC, and these employees and services were contracted out to CPUC.)

f) Please provide a more detailed explanation as to why two positions are now required to oversee the utility (e.g. the General Manager and the Manager of Finance), when in the past (e.g. prior to 2017) only one position was required to manage CPUC.

g) Please confirm that all of CPUC's employees' salaries are adjusted on a yearly basis to reflect a rate of 2% (e.g. the rate used by CPUC for budgeting purposes) or whether effective January 1, 2018 CPUC used the adjusted price cap index as an inflation factor.

   i. If yes, please describe why CPUC's employees' salaries should be adjusted for a rate of 2%, when the inflation rate is 1.5%.
   ii. If no, please provide more detail on the adjusted price cap index CPUC proposes to use as an inflation factor. For example in 2018 did CPUC use an adjusted price cap index of 0.75% to adjust salaries (i.e. the OEB's 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)?
   iii. If no, please describe what rate is used to adjust the salaries of its employees.
   iv. If no, please also describe why some employees are adjusted and some employees are not adjusted.

h) Please describe whether any CPUC employees receive performance pay or a bonus, and how this compensation is structured.

i) Please explain why CPUC did not use specific benchmarking studies to determine salary ranges other than basing its inflation rate and salary at the Town of Chapleau.

j) Please provide more detail how CPUC employees' salaries are compared to other salaries at the Town of Chapleau.

k) Please discuss further how CPUC has maintained the same number of FTEs between 2012 and 2019, while at the same time using other measures to complete its required work. Please discuss the extent to which overtime, contracting out (as noted above in the sixth reference), or other measures of this kind were used.

l) OEB staff notes that in the Excel Appendix 2-K, there are two columns relating to 2012 (OEB approved and actual), but both columns have identical numbers. Please update the evidence to show 2012 OEB approved and 2012 actual.

m) OEB staff notes that the PDF Appendix 2-K in Exhibit 4 has only one column for 2012 and does not specify whether it is 2012 OEB approved or 2012 actual. Please update the evidence to show 2012 OEB approved and 2012 actual.

Responses:

a) CPUC being a small remote community found it very necessary to have full time people in the positions of full-time lineman, in financing and management for safety, reliability, customer service and to maintain a safe reliable distribution system. We replaced a previous manager who was being paid well below the market median, with a Manager of Finance and moved the Lineman Assistant Administrator to General Manager. These salary increases are necessary to attract and retain qualified employees. It was unrealistic to expect to be able to hire a replacement at that discount. CPUC needs two full time linemen for safety and trouble calls and in order to meet the DSC must have a qualified person on site of an emergency call within 2 hrs. This would not happen because of our remoteness if we did not have the staff. Any alternatives would not be in the best interest of the company nor its ratepayers.

b) Please refer to 4-Staff-44.

c) In 2012 not 100% of compensation was allocated to CPUC. A portion remained in CESC. If 100% had been allocated to CPUC the numbers would have look like this: CESC allocation being different every year make is difficult to explain. The section below shows what the numbers would have been if we weren't a "virtual" utility. his shows that we haven't had a big increase like they think we have.

Management in 2012 would have been 71,033. In 2019 CPUC has budgeted 149,760. The difference would have been **78,727**. The difference would be attributed to:

One lineman being promoted to Management – 70,000
Wage increases over 7yrs – 8,727 (1,246 per year).

Lineman in 2012 would have been 190,952. In 2019 CPUC budgeted 158,309. The difference would have been **(32,643)**. The difference would be attributed:

One less lineman (promoted to management) – (67,329)
The portion of manager that is in lineman – 23,650
Wage increases over 7yrs – 12,000 (6k per lineman, 850per year)

Clerk in 2012 would have been 36,373. In 2019 CPUC budgeted 41,455. The difference would have been **5,082**. The difference would be attributed to:

Wage increase over 7yrs – 5,082 (726per year)

On Call in 2012 was 7,800. In 2019 CPUC budgeted 13,000. The difference would be **5,200**. The difference can be attributed to:

On call was increase from 150 weekly to 250 weekly

Total difference – 56,366 (8,000 per year)

CPUC only compared the salary and wages portion not the benefits portion, to me the benefits are all relevant to the wages.

d) Table 18 shows the amount of staff throughout 2018, whereas table 22 shows the staff remaining at the end of 2018. CPUC had two summer students in 2018 but they were gone by September.

e) For rate making purposes, for reporting purposes, for benchmarking purposes, CPUC much like other virtual utilities, is required to show its employees and costs as it would if it had been a traditional utility.

f) Because one person should not be doing the work of multiple people. Yes, CPUC is a small utility but CPUC still has the same obligations as a large utility. Same OEB and IESO reporting, regulations to follow, billing, payroll, payables……. Having one person do all the jobs is not realistic and an unfair expectation. It was too much for the one person who was a veteran for 20 years imaging how much it would have been for a new person coming in.

g) CPUC's employee salaries are adjusted on a yearly basis based on the union contract from the Township of Chapleau employees.

i. Effective Jan 1, 2018 CPUC used a 1.5% rate increase, which would match the inflation rate.
ii. N/A
iii. The rate used is based on the union contract from the Township of Chapleau employees.
iv. All employees are adjusted

h) No performance pays or bonus

i) CPUC did not use the Town for benchmarking to determine the salary ranges only used them for the yearly increases. They had starting wages back in the day and CPUC has always used the Town to determine increases. CPUC did however hire a company to do the wage study in 2018 to see if CPUC were competitive and found out that CPUC is not and that our employees are in fact under paid:

Lineman – 22.16% below market
Clerk – 7.4% below market
Manager of Finance – 6.08% below
General Manager – 7.87% below market

j) They are not compared to the Town, we just give our employees the same wage increases per year.

k) This is explained in a combination of a) to j) above

l) And m) Chapter 2 appendices

4-Staff-49

Ref: Exhibit 4, Table 20 – Benefit Expenses

Question:

a) Please update Table 20 to show balances for the year 2012 OEB-approved.

Responses:

a) This question was asked and answered in CPUC's response to incomplete. Please see CPUC's response question 30 & 31.

4-Staff-50

Ref: Table 21 - Details Compensation Accounts
Exhibit 4, page 30

Preamble:

At the above noted first reference, CPUC showed the following table.

Table 21 - Details Compensation Accounts

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)[1]								
Total Salary and Wages including overtime and incentive pay								
Management+ linemen (including executive)	193,227	197,803	205,360	201,266	232,699	230,374	314,100	308,069
• Salary Increase 2%)		2%	2%	2.5%	2%	2%		
• CPUC Management Allocation (virtual)	84%	87%	87%	81%	85%	89%		
• CPUC Linemen Wages Allocation (virtual)	100%	100%	100%	100%	100%	100%		
• CPUC Clerk Wages Allocation (virtual)	84%	87%	87%	81%	81%	89%		
• CPUC Holiday Allocation (virtual)	84%	87%	87%	81%	81%	89%		
• CPUC on-call Allocation (virtual)	100%	100%	100%	100%	100%	100%		
• Overlap of role for succession purposes						+$14.5K		
• Promotion of Senior Lineman to General Mgr						*+6.7K		

At the above noted second reference, CPUC stated the following:

> …increase in management costs related to the change in a corporate structure where 100% of management salaries are now embedded in OM&A…

Questions:

a) Please complete Table 21 to show 2018 actuals and 2019 projected.

b) Please explain how Table 21 shows CPUC employees when prior to 2018 CPUC operated as virtual utility with no employees.

c) Please confirm that salaries are allocated a specific percentage to CPUC from CES prior to 2018 and explain the allocations.

d) Please confirm that effective January 1, 2018, 100% of the above noted salaries are now being paid by CPUC, including both management and non-management salaries. Please explain why in the past allocations less than 100% may have been sufficient to maintain CPUC's operations.

e) Please explain why the "Total Salary and Wages including overtime and incentive pay" in Table 21 do not match the same line in Table 18. For example:

i. 2012 – Table 18 shows $250,370; Table 21 shows $193,227
ii. 2013 – Table 18 shows $262,148; Table 21 shows $197,803
iii. 2014 – Table 18 shows $273,166; Table 21 shows $205,360
iv. 2015 – Table 18 shows $263,078; Table 21 shows $201,266
v. 2016 – Table 18 shows $296,424; Table 21 shows $232,699
vi. 2017 – Table 18 shows $300,309; Table 21 shows $230,374
vii. 2018 – Table 18 shows $367,550; Table 21 shows $0
viii. 2019 – Table 18 shows $362,524; Table 21 shows $0

Responses:

a) The allocation shown at Table 21 stopped when CPUC ceased to be a virtual utility. Therefore, there is no longer any allocation in 2018-2019 as 100% of the employee's time is not allocated to CPUC.

b) See response to 4-Staff-48.

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)[1]								
Total Salary and Wages including overtime and incentive pay								
Management (including executive)	**$59,567**	**$64,246**	**$60,027**	**$60,695**	**$87,775**	**$109,622**	**$149,000**	**$149,760**
• Salary Increase 2%)		2%	2%	2.5%	2%	2%		
• CPUC Management Allocation (virtual)	84%	87%	87%	81%	85%	89%		
Non-Management (union and non-union)	**$190,803**	**$197,902**	**$213,139**	**$202,384**	**$208,649**	**$190,688**	**$218,550**	**$212,764**
• CPUC Linemen Wages Allocation (virtual)	84%	87%	87%	81%	81%	89%		
• CPUC Clerk Wages Allocation (virtual)	84%	87%	87%	81%	81%	89%		
• CPUC Holiday Allocation (virtual)	84%	87%	87%	81%	81%	89%		
• CPUC on-call Allocation (virtual)	100%	100%	100%	100%	100%	100%		
• Overlap of role for succession purposes						+$14.5K		
• Promotion of Senior Lineman to General Mgr.						*+6.7K		
Total	**$250,370**	**$262,148**	**$273,166**	**$263,078**	**$296,424**	**$300,309**	**$367,550**	**$362,524**

Yes, they weren't "CPUC" employees but that was the cost of those employees to do lineman duties. (same as 4-48 e)

c) CPUC confirms that CPUC now pays 100% of the above noted salaries directly. In the past the above noted salaries were 100% paid by CPUC's affiliate CESC, and CPUC was charged a portion of the salaries based on a time allocation. It appears to CPUC that the affiliate CESC was undercharging CPUC, as the amount charged to CPUC combined with the amount CESC was able to charge to customers other then CPUC was not enough to cover the full amount of the salaries. In the event CESC were to have continued operating (which is not the case) and CPUC did not take on 100% of the salaries directly, the allocation of costs to CPUC by CESC would have had to increase to properly reflect the percentage of the total work those employees performed for CPUC as opposed to customers of CESC other then CPUC. Under the current arrangement CPUC is appropriately paying the full cost of the salaries, with any revenue generated through the use of those employees to perform work for customers other than CPUC distribution customers treated as a revenue offset against the CPUC revenue requirement

d) Yes 100% of salaries are now being paid by CPUC but some salaries are non utility related. CPUC performs non utility related work such as street light maintenance, tree trimming (not related to our lines), work for Hydro One. The portion of those salaries/wages are put into 4380 non utility related expenses.

e) The table in the application should have show the information at the table in section b) of this IR

4-Staff-51

Ref: Exhibit 4, Table 13, OEB Appendix 2-L Recoverable OM&A Cost per Customer and FTE
Exhibit 4, page 28

Preamble:

At the above noted first reference, the following table is shown.

Table 13 – OEB Appendix 2-L Recoverable OM&A Cost per Customer and FTE[8]

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Customers	1,281	1,226	1,224	1,222	1,227	1,221	1,221	1,209
Total Recoverable OM&A	670,607	638,471	744,673	730,565	744,037	716,586	809,404	821,163
OM&A cost per customer	524	521	609	598	606	587	663	679
Number of FTEs	5	5	5	5	5	5	5	5
Customers/FTEs	256	245	245	244	245	244	244	242
OM&A Cost per FTE	134,121	127,694	148,935	146,113	148,807	143,317	161,881	164,233
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
OM&A Costs								
O&M	$289,711.10	$220,412.01	$223,210.54	$208,239.31	$236,332.09	$237,909.06	$247,400.00	$244,370.00
Admin Expenses	$380,895.82	$418,058.85	$521,462.73	$522,325.49	$507,704.50	$478,676.77	$562,004.00	$576,793.00
Total Recoverable OM&A from Appendix 2-JB [5]	$670,606.92	$638,470.86	$744,673.27	$730,564.80	$744,036.59	$716,585.83	$809,404.00	$821,163.00
Number of Customers [2,4]	1,281	1,226	1,224	1,222	1,227	1,221	1,221	1,209
Number of FTEs [3,4]	5	5	5	5	5	5	5	5
Customers/FTEs	256.20	245.10	244.70	244.30	245.40	244.20	244.20	241.76
OM&A cost per customer								
O&M per customer	$226.16	$179.85	$182.44	$170.48	$192.61	$194.85	$202.62	$202.16
Admin per customer	$297.34	$341.13	$426.21	$427.61	$413.78	$392.04	$460.28	$477.15
Total OM&A per customer	**$523.50**	**$520.99**	**$608.64**	**$598.09**	**$606.39**	**$586.88**	**$662.90**	**$679.31**
OM&A cost per FTE								
O&M per FTE	$57,942.22	$44,082.40	$44,642.11	$41,647.86	$47,266.42	$47,581.81	$49,480.00	$48,874.00
Admin per FTE	$76,179.16	$83,611.77	$104,292.55	$104,465.10	$101,540.90	$95,735.35	$112,400.80	$115,358.60
Total OM&A per FTE	$134,121.38	$127,694.17	$148,934.65	$146,112.96	$148,807.32	$143,317.17	$161,880.80	$164,232.60

At the above noted second reference, CPUC stated the following:

> OEB Appendix 2-L Employee Costs at Table 13 – OEB Appendix 2-L Recoverable OM&A Cost per Customer and FTE below shows an OM&A cost per customer of $679 in 2019 in comparison to $524 in the 2012. CPUC is aware of the significant impact this application has on its customer however, the utility feels that the costs presented in this application reflect the minimum costs required to operate a utility. In CPUC's view, the necessarily high cost of serving such a small customer base in such a remote area has been recognized by the provincial government in the extension of DRP funding towards CPUC's customers. That said, CPUC will continue to look for ways of finding efficiencies to help reduce costs for its customers.

Questions:

a) Please explain how Table 13 shows CPUC employees when prior to 2018 CPUC operated as virtual utility with no employees.

b) As noted earlier in IR# 4-Staff-48, considering total compensation costs have increased of $116,633, please explain CPUC's statement that it is operating a minimum cost structure, when comparing 2019 test year to 2012.

c) Please explain CPUC's statement that there is a "necessarily high cost of serving such a small customer base in such a remote area."

d) Please explain in more detail how CPUC will continue to look for ways of finding efficiencies to help reduce costs for its customers. Please quantify such efficiencies and forecast the impact on CPUC's 2019 proposed revenue requirement.

Responses:

a) For rate making purposes, for reporting purposes, for benchmarking purposes, CPUC much like other virtual utilities, is required to show its employees and costs as it would if it had been a traditional utility.

b) As explained <u>in detail</u> in the application, prior to 2018, the utility's costs were shared with the affiliate. Please refer to 4-Staff-48 for response.

c) Some of CPUC's requirements and costs are as onerous as they would be for a Hydro One or Toronto Hydro for example. A pole costs the same, if not more, in a remote service area as it would in a high-density urban area. However, a small remote utility has fewer customers to spread these costs across. Being remote also limits the availability of local experts CPUC can use. CPUC often has to outsource from out of town.

d) Chapleau is a small community and, as such, it can be difficult to optimize the use of CPUC's linemen. That said, CPUC will continue to look for opportunities to offset its costs by increasing it's non utility related revenue. CPUC cannot quantify work that has not yet materialized but CPUC will continue to look for ways to reduce costs through revenue offsets.

4-Staff-52

Ref: Exhibit 4, Table 37 – OEB Appendix 2-M Regulatory Costs
Exhibit 4, page 19

Preamble:

At the above noted reference, CPUC has included the following table:

Table 37 – OEB Appendix 2-M Regulatory Costs[25]

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year Board Approved	2012	2013	2014	2015	2016	2017	2018	2019
1	OEB Annual Assessment	5655		On-Going	$ 14,520	$6,785.20	$18,809.32	$7,225.81	$7,774.19	$8,933.79	$8,933.79	$9,000.00	$9,195.00
2	OEB Section 30 Costs (Applicant-originated)												
3	OEB Section 30 Costs (OEB-initiated)												
4	Expert Witness costs for regulatory matters												
5	Legal costs for regulatory matters												
6	Consultants' costs for regulatory matters	5630		On-Going		$0.00	$0.00	$0.00	$0.00	$0.00	$33,000.00	$33,000.00	$33,000.00
7	Operating expenses associated with staff resources allocated to regulatory matters												
8	Operating expenses associated with other resources allocated to regulatory matters												
9	Other regulatory agency fees or assessments	5655		On-Going		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
10	Any other costs for regulatory matters (Cost of Service)	5655		One-Time		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,300.00
	Any other costs for regulatory matters (OEB Audit)	5655		One-Time		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	Intervenor costs												
12	Sub-total - Ongoing Costs		$ -		$ -	$6,785.20	$18,809.32	$7,225.81	$7,774.19	$8,933.79	$41,933.79	$42,000.00	$42,195.00
13	Sub-total - One-time Costs		$ -		$ -		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,300.00
14	Total		$ -		$ -	$6,785.20	$18,809.32	$7,225.81	$7,774.19	$8,933.79	$41,933.79	$42,000.00	$63,495.00

At the above noted second reference, CPUC stated the following:

> At the beginning of 2017, CPUC hired Tandem Energy Services to assist the utility with its regulatory requirements CPUC entered in a 4-year contract with Tandem Energy Services for regulatory services assisting the utility in creating a work environment that facilitates the understanding and support of the change. Services include;
>
> - Drafting IRM and Cost of Service application including response to IRs and settlement proposal.
> - Representing the utility in settlement conference, oral hearings.
> - Financial analysis reporting (Tracking of Benchmarking, ROE, projected income, budget review).
> - Update to Conditions of service.
> - Assistance with RRR Annual filing.
> - Creation of utility specific models to facilitate RRR reporting or Financial Reporting.
> - Creation of Business Plan and Customer Outreach Plan.
> - Regular updates to the Board of Director

- And provide any other regulatory services as they arise.

Questions:

a) Please confirm that CPUC is requesting regulatory costs of $63,495 in its 2019 proposed revenue requirement.

b) Please confirm that the services provided by the annual $33k cost pertaining to "Consultants' costs for regulatory matters" are described in the above noted second reference. If this is not the case, please explain.

c) Please explain why the annual $33k cost in 2017, 2018, and 2019 pertaining to "Consultants' costs for regulatory matters" was initiated in 2017, when around the same time CPUC doubled its management team from one FTE to two FTEs. Please provide more details as to why the services provided by this consultant may not be instead provided by one of CPUC's new management team members.

Responses:

a) Confirmed

b) Confirmed

c) CPUC's total FTEs did not increase around the time that CPUC entered in its contract with Tandem Energy Services; rather, upon the retirement of its Secretary/Treasurer, the responsibilities of that position were distributed between an existing lineman/administrative assistant, who was promoted to a management position, and a newly hired treasurer. While technically CPUC's "management team" doubled, CPUC did not acquire any incremental resources or expertise, particularly with respect to the regulatory obligations imposed on CPUC.

CPUC requires substantial incremental resources and expertise in order to successfully prepare for and file a COS application; the contract with Tandem Energy Services provides those resources and expertise, while also providing those resources throughout the IRM period with respect to non-COS related regulatory matters, all at a fixed cost that is absorbed over a 4-year period. The result is that:

- CPUC has access to incremental resources and expertise to attend to regulatory matters for the duration of the contract without the need to hire any full-time regulatory staff, the cost of which would be prohibitive to a company the size of CPUC,

- CPUC has access to the incremental resources and expertise it requires for the preparation of its COS application,
- CPUC has achieved cost certainty with respect to its consultant costs in support of its COS and non-COS related regulatory requirements for a four-year period; and
- CPUC has substantially normalized the cost consequences to it of its COS related expenses by entering into a multiyear contract, mimicking the Board's practice of amortizing COS related costs over the course of an IRM period.

4-Staff-53

Ref: Exhibit 4, page 49

Preamble:

At the above noted reference, CPUC referred to a services agreement between CPUC and CES that was in effect until January 1, 2018. CPUC stated the following:

> **Operation and Maintenance Service Agreement (2012-2017)**
>
> Chapleau Public Utilities Corporation and Chapleau Energy Services Corporation had an operation and maintenance service agreement between the two companies. The Utility employed the Services Company to supply material, labour and equipment required for new construction, repairs and maintenance of the Utility's distribution system, management support, billing and collection, rent, phone, postage and office equipment. All services were charged to the Distribution Company at direct cost-plus applicable overhead (no mark-up).
>
> **Allocation Methodology (2012-2017)**
>
> The Allocation Methodology for corporate and shared services is identified below in Appendix 2-N. These allocators were reviewed annually by CPUC's Accountants/Auditors.
>
> Appendix 2-N has been completed for the services provided for the period of 2012-2017. Each Appendix 2-N is followed by a detailed breakdown of the allocation between the affiliate and CPUC. The service agreement is presented at Appendix E of this Exhibit.
>
> CPUC has not provided a reconciliation between Appendix 2-N and Other Revenues as revenues and expenses from non-utility operations are netted out before they hit the books (or trial balances). CPUC and its accountant attest that there are not profits or losses generated from these transactions and that costs are equal to revenue.
>
> **Variance Analysis from last Board Approved (2012-2018)**
>
> In its 2012 Cost of Service, CPUC presented $417,936 in corporate cost allocation for its 2012 test year. CPUC notes that the OEB did not approve a specific amount for shared services in its decision. CPUC no longer has any affiliates and as such, its current corporate cost allocation are $0. The variance from its last board approved is therefore -$417,936.

Questions:

a) Please describe the calculations that were used to support that CES charged CPUC at "direct cost-plus applicable overhead (no mark-up)." For example, were factors such as market value, fully allocated costs, or some other measures considered?

b) Please explain why no mark-up was charged by CES to CPUC.

c) Please explain why “revenues and expenses from non-utility operations are netted out before they hit the books (or trial balances).”

d) It is OEB staff’s understanding that CPUC did not provide any services to CES. Please explain why no profits or losses were generated from the transactions between CES and CPUC (i.e. why revenues were equal to costs), as:

i. CPUC did not earn any revenue from CES, so no revenues would be reflected in non-utility revenue, Account 4375. If is not the case, please explain. OEB staff notes that Account 4375, Revenues from Non Rate-Regulated Utility Operations, is included in the calculation of the Other Revenue which is used to offset CPUC’s revenue requirement.

ii. The costs charged by CES to CPUC for distribution related activities would have been reflected in CPUC’s OM&A, as opposed to non-utility expense, Account 4380. If this is not the case, please explain. OEB staff notes that Account 4380, Expenses of Non Rate-Regulated Utility Operations, is included in the calculation of the Other Revenue which is used to offset CPUC’s revenue requirement.

e) Please confirm that CPUC’s OM&A incorporated into the 2019 test year revenue requirement is solely related to distribution related activities, as opposed to some being related to affiliate activities. If this is not the case, please explain.

f) OEB staff notes CPUC’s statement that it no longer has any affiliates but seeks further clarification. Please quantify any impact of the following on the 2019 test year revenue requirement, with a description of each change:

i. Any affiliate costs that are included in both 2019 test year OM&A and also included as a reduction to 2019 test year other revenue – Appendix 2-H

ii. Any affiliate revenues that are neither included as reduction to 2019 test year OM&A and also not included as an addition to 2019 test year other revenue – Appendix 2-H

g) Please confirm that any revenue related to MicroFit charges has been recorded as a revenue off-set in Account 4235 – Miscellaneous Service Revenue and is not included as part of the base distribution revenue requirement. If this is not the case, please provide an explanation.

h) OEB staff notes that the 2012 cost of service decision was silent regarding corporate cost allocations. CPUC's above statement shows that in its 2012 cost of service proceeding it presented $417,936 in corporate cost allocation for its 2012 test year. Does CPUC mean that an equal amount of $417,936 was recorded in both non-utility revenue and non-utility expense, as well as an additional $417,936 recorded in OM&A? If this is not the case, please explain.

i) Has CPUC recorded a similar amount of $417,936 in its proposed 2019 OM&A? Please explain.

Responses:

a) PUC just calculated the hours worked for CESC, the balance of the hours was divided by the total hours worked and CPUC used that percentage to calculate the costs charged to PUC.

b) CESC was created to provide services for the community that weren't available and that a utility was not allowed to do. The intention was not to make money off of CPUC; accordingly, no mark up was applied to the charges to CPUC.

c) This is the manner in which the accounting was done prior to the new management coming into force. CPUC notes that other smaller or remote utilities have done it in this manner in the past. Since the cost offset the revenues, there is not effect on the bottom line of the utility.

d) i) CESC stuff wasn't posted to 4375. The only items in 4375 before 2018 was CDM related. In 2018 and forward CPUC does have Non utility related revenue budgeted in 4375.

ii) Yes it was reflected in CPUC's OM&A and not to non-utility expenses, account 4380.

e) Confirmed.

f) i) and ii) CPUC confirms that there are no costs or revenues associated with affiliates (as CPUC no longer has an affiliated company) in Appendix 2-H.

g) CPUC has no microfit customers.

h) The amount was only recorded in the OM&A. Any cost charged to CPUC from CESC was only for distribution costs and went to OM&A, nothing went to non utility related accounts.

i) No, see response to f).

4-Staff-58

Ref: Exhibit 1, 2017 Business Plan, page 37

Preamble:

At the above reference, CPUC stated the following regarding its General Manager and succession planning:

> Within the next 2 years, CPUC may see the leave of its current General Manager due to his eligibility to retire. The utility recognizes that finding a candidate with industry specific competencies in smaller rural LDCs is tough. As such, over the past year, CPUC has put substantive effort into its succession planning which involves training its employees on every aspect of the utility. Documenting processes have also become a priority.

Question:

a) Please discuss any succession planning CPUC has conducted to address its aging workforce, as well as the associated impact on the 2019 test year revenue requirement.

Responses:

a) CPUC, in collaboration with Cooperative Hydro Embrun, Hydro Hawkesbury, Hydro 2000 and Hearst Power has started putting together a Successions and Talent Management Plan. The document is still in its infancy but intends on being completed by the end of 2019. The document will detail the Succession Plan steps, benefits of a talent management and succession plan, roles of the constituencies and a communication strategy.

4-Staff-59

Ref: Exhibit 4, page 8

Preamble:

At the above noted reference, CPUC stated the following:

> CPUC is of the opinion that there is a minimum cost required to operate any utility and that its proposed OM&A reflects this minimum required costs. That said, CPUC will continue to seek savings and efficiencies to minimize costs increases for its customers going forward. The proposed OM&A expenses for 2018-2019 are in line with what CPUC expects regular yearly OM&A costs will be going forward.

Questions:

a) Please describe in more detail how CPUC will continue to seek savings and efficiencies to minimize costs increases for its customers going forward.

Responses:

a) From an O&M perspective, CPUC does not have the option of using a 3rd party operating firm such as other utilities do. It must therefore operate with a minimum of 2 lineperson for safety purposes. That said, CPUC will continue to look for revenue offsets opportunities to help offset these costs wherever possible. With respect to Administrative Costs, as explained in the application, the proposed OM&A expenses for 2018-2019 are in line with what CPUC expects regular yearly OM&A costs will be going forward. CPUC will continue to look for efficiencies such as cost sharing for example to help reduce Administrative cost per customer.

4-Staff-60

Ref: Exhibit 4, Section 4.6.1 Non-Affiliate Services

Preamble:

At the above reference, CPUC's purchases of non-affiliate services is discussed and CPUC stated that:

> CPUC purchases equipment, materials, and services in a cost-effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet CPUC's needs. The procurement of goods and services for CPUC is carried out with highest of ethical standards and consideration to the public nature of the expenditures…
>
> … Although tendering processes provide essential information to potential suppliers and ensure a fair chance for businesses, the tendering process is not always possible in small towns where there is a limited supply of skilled services that can provide support to utilities. The utility's written procurement policy is presented at Appendix D21 however as described above, the General Manager, with the input of board members, approves all purchases of goods and services.
>
> Hydro One, IESO, Chapleau Energy Services (until 2017), Tandem Energy Services Inc. Erth Holdings, the Town of Chapleau have consistent yearly transactions, some in excess of the materiality threshold of $50,000. These specific suppliers offer services that are not commonly found in the service area or general surrounding area or offer efficiencies due to their intimate knowledge of CPUC's distribution system or the industry...

Questions:

a) Please discuss how it is determined which services will be undertaken by CPUC and which will be acquired through non-affiliates.

Responses:

a) If CPUC has the internal expertise and time to do it in-house, it will. If it deems that it does not, it will look for assistance in a 3rd party firm.

4.0-VECC-27

Reference: Appendix 2-JA and Appendix 2-JC

a) Please update the above referenced tables for 2018 actual financial results.

Responses:

a) Appendix 2-JA is presented at 4-Staff-46.

b) Appendix 2-JC is shown below.

Description	BA 2012	2012	2013	2014	2015	2016	2017	2018	2019
5016-Distribution Station Equipment - Operation Labour	$ 4,500	$ 2,900	$ 2,224	$ 2,531	$ 3,468	$ 2,991	$ 2,030	$ 2,281	$ 2,327
5017-Distribution Station Equipment - Operation Supplies and Expenses	$ 1,200	$ 1,124	$ 270	$ 859	$ -	$ -	$ 50	$ 50	$ 51
5020-Overhead Distribution Lines and Feeders - Operation Labour	$ 149,400	$ 160,543	$ 165,675	$ 179,101	$ 171,305	$ 178,142	$ 162,957	$ 164,676	$ 171,309
5025-Overhead Distribution Lines and Feeders - Operation Supplies and	$ 48,000	$ 31,167	$ 50,236	$ 36,131	$ 30,994	$ 53,231	$ 63,381	$ 31,364	$ 31,991
5065-Meter Expense	$ 600	$ 92,076	$ 1,120	$ 1,675	$ 572	$ 514	$ 7,010	$ 392	$ 400
5095-Overhead Distribution Lines and Feeders - Rental Paid	$ 1,740	$ 1,900	$ 887	$ 2,914	$ 1,900	$ 1,453	$ 2,481	$ 2,495	$ 2,545
5310-Meter Reading Expense	$ 29,000	$ 22,033	$ 34,612	$ 30,967	$ 32,959	$ 35,466	$ 41,027	$ 41,226	$ 41,040
5315-Customer Billing	$ 51,600	$ 69,445	$ 73,805	$ 74,871	$ 78,035	$ 78,927	$ 80,401	$ 73,273	$ 87,078
5335-Bad Debt Expense	$ 3,600	$ 4,107	$ 6,669	$ 29,771	$ 18,900	$ 6,763	-$ 208	$ 10,000	$ 5,000
5410-Community Relations - Sundry	$ 600	$ 115	$ 415	$ 415	$ 115	$ 415	$ 415	$ -	$ -
5605-Executive Salaries and Expenses	$ 13,200	$ 13,200	$ 13,200	$ 12,200	$ 13,200	$ 13,200	$ 13,100	$ 13,200	$ 16,200
5610-Management Salaries and Expenses	$ 60,840	$ 59,567	$ 64,246	$ 60,027	$ 60,695	$ 87,775	$ 109,622	$ 143,711	$ 149,760
5615-General Administrative Salaries and Expenses	$ 15,480	$ 13,718	$ 14,304	$ 15,000	$ 14,457	$ 17,664	$ 14,465	$ 18,693	$ 18,197
5620-Office Supplies and Expenses	$ 24,000	$ 19,194	$ 22,017	$ 20,587	$ 25,505	$ 26,672	$ 19,138	$ 27,564	$ 21,850
5630-Outside Services Employed	$ 106,400	$ 58,598	$ 39,715	$ 49,125	$ 110,675	$ 76,785	$ 65,107	$ 46,929	$ 30,061
5635-Property Insurance	$ 17,040	$ 13,544	$ 14,491	$ 13,770	$ 14,916	$ 4,421	$ 9,393	$ 9,373	$ 9,690
5640-Injuries and Damages	$ 6,540	$ 6,425	$ 6,809	$ 7,500	$ 7,021	$ 7,534	$ 8,625	$ 11,104	$ 10,180
5645-Employee Pensions and Benefits	$ 61,920	$ 63,665	$ 73,124	$ 69,280	$ 63,953	$ 73,205	$ 83,742	$ 94,734	$ 96,980
5655-Regulatory Expenses	$ 14,520	$ 6,785	$ 18,809	$ 7,226	$ 7,774	$ 8,934	$ 8,392	$ 72,345	$ 63,495
5665-Miscellaneous General Expenses	$ 32,160	$ 28,499	$ 33,844	$ 128,723	$ 72,120	$ 67,942	$ 23,458	$ 18,383	$ 24,650
6205-Sub-account LEAP Funding	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000

4.0-VECC-28

Reference: Exhibit 4, Appendix 2-K, page 42 (PDF).

a) Please explain more fully the position change (General Manager and Manager of Finance) that occurred in 2016. Specifically please show the two prior job salary ranges and the new positon salary ranges (not individual salaries).
b) Did CPUC hire a new person/persons or was the change in positions completed through internal promotions?
c) Since 2012 how many retirements and new hires have taken place?

Responses:

a) In 2015 the current Sec/Treas announced her retirement. In preparation for this the Sec/Treas explained to the board at the time that the position was too much for only one person, especially a new person. The board decided to split the job up. The main split was giving the supervision/overhaul management of the utility over to the General Manager.

CPUC does not have salary ranges.

b) A new person was hired for the Sec/Treas position, now titled Manager of Finance. The new position of General Manager was created and completed through internal promotion. The Lineman/Assist. Admin person was the one promoted, but the Lineman/Assist Admin job was left vacant.

c) Only the retirement of the Sec/Treas since 2012 and only the replacement was a new hire since 2012. Only other hire would have been the college Lineman Co-op student in the summer of 2018 for 4 months.

4.0-VECC-29

Reference: Exhibit 4, Appendix 2-K, PDF pg. 42

a) Please update Appendix 2-K to show 2018 actuals and to add a column showing the total compensation capitalized in each year.

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	1	1	1	1	2	2	2	2
Non-Management (union and non-union)	4	4	4	4	3	3	5	3
Total	**5**	**5**	**5**	**5**	**5**	**5**	**7**	**5**
Total Salary and Wages including overtime & incentive pay								
Management (including executive)	$59,567	$64,246	$60,027	$60,695	$87,775	$109,622	$143,712	$149,760
Non-Management (union and non-union)	$190,803	$197,902	$213,139	$202,384	$208,649	$190,688	$200,177	$212,764
Total	**$250,370**	**$262,148**	**$273,166**	**$263,078**	**$296,424**	**$300,309**	**$343,889**	**$362,524**
Total Benefits (Current + Accrued) -								
Management (including executive)	$2,925	$3,132	$3,216	$3,039	$5,924	$5,123	$12,669	$11,555
Non-Management (union and non-union)	$10,793	$11,172	$11,784	$11,419	$11,740	$9,343	$6,024	$6,642
Total	**$13,718**	**$14,304**	**$15,000**	**$14,457**	**$17,664**	**$14,465**	**$18,197**	**$18,197**
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$62,493	$67,378	$63,243	$63,733	$93,699	$114,744	$156,380	$161,315
Non-Management (union and non-union)	$201,596	$209,074	$224,923	$213,802	$220,389	$200,030	$206,201	$219,406
Total	**$264,088**	**$276,452**	**$288,166**	**$277,536**	**$314,088**	**$314,775**	**$362,582**	**$380,721**
Integrity Check from accounts 5020/5610/5615	$233,829	$244,225	$254,128	$246,457	$283,582	$287,044	**327,081**	
Wages posted to 5315	$30,259	$32,227	$34,038	$31,078	$30,506	$27,731	**$35,500**	
Difference	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	

Responses: Please find below the compensation capitalized in each year:

2012 – 0
2013 – 7,471.61
2014 – 3,660.20
2015 – 6,221.63
2016 – 1,549.00
2017 – 4,928.48
2018 – 9,342.05

4.0-VECC-30

Reference: Exhibit 2, Table F-2, PDF pg.44

a) For each asset category which is outside the minimum or maximum TUL of the Kinectrics Report (5) please explain the reason for Chapleau's different TUL and provide the study or support for using the different asset life.

Responses: (From KPMG)
There are three assets that are outside of the Kinetrics report suggested useful lives:
Acct 1808 – Buildings
- Kinetrics report 50 to 75 years
- Chapleau PUC useful life 25 years

Based on the past history of the buildings with Chapleau (and northern Ontario) the building life was deemed to be 25 years.

Acct 1802 – Computer Equipment
- Kinetrics report 3 to 5 years
- Chapleau PUC useful life 2 years

Given the obsolescence of most computer equipment, 2 years was deemed to be appropriate.

Acct 1860 – Smart Meters
- Kinetrics report 5 to 15 years
- Chapleau PUC useful life 20 years

Given that the smart meters are a newer technology 20 years was deemed to be the useful life. IFRS technically requires us to look at the useful lives every year and if better information is available to support the useful life.

The change in useful lives would have an immaterial impact on the financial statements in any given year given that PUC does not have significant capital assets.

4.0-VECC-31

Reference: Exhibit 2, Table F-2, PDF pg.7 & 50

Pre-amble – CPUC explains: *The methodology used to allocate corporate cost allocations was based on a one-way percentage which upon further analysis revealed that the utility had been benefiting from cost sharing opportunities with its affiliate at the detriment of the affiliate which ended up shutting its operations and doors on December 31, of 2017*.

a) It is unclear what a "one-way percentage" methodology is. Please explain more fully.
b) What was the last full year in which costs were allocated to the affiliate? What were those costs?
c) What is the net amount of costs that are now being absorbed by CPUC due to the demise of the affiliate?
d) What was the name and function of this affiliate?

Responses:

a) Only the affiliate was charging CPUC a percentage of the costs. CPUC never charged the affiliate for a percentage of their costs.

b) 2017. $487,733.28

c) The percentage is different every year. On average, though, from 2012-2017 the allocation percentage was 83%. To use 2017 was solely used, as an example (used in b), the costs would have been another, $44,579.31. however, this incremental amount is partially offset by any revenue from serving no utility customers.

d) Chapleau Energy Services Corporation. In addition to providing services to CPUC CESC performed non-utility work such as streetlight maintenance, chimney cleans, and Hydro One rural work, some of which CPUC now performs.

4.0-VECC-32

Reference: Exhibit 2, Table F-2, PDF pg.44

a) What are the incremental costs in moving to monthly billing?
b) When did CPUC complete the change from bi-monthly to monthly billing?
c) How many customers (# & %) are provided e-bills?

Responses:

a) CPUC only had approx. 400 total customers that were being billed bi-monthly. It wasn't a substantial amount for us to do the switch. Each month equated to only an extra 200 bills.

Stamps - $170 (.85 x 200)
Envelopes - $14 (.07 x 200)
Bills - $22 (.11 x 200)
Cost per month - $206
Tim Sinclair Consulting to change billing system to accommodate – approx.. $400 (5hrs x $80)

b) September 2014.

c) CPUC doesn't have e-bills.

4.0 -VECC -33

Reference: Exhibit 4, Appendix 2-M, pdf pg. 75

a) Please provide the amount of one-time application costs that have been incurred in 2018.
c) Please clarify if these costs are being reported in the updated cost for Appendix 2-JA.

Responses:

a)

- Translation cost of customer engagement letter and presentation: $102
- Customer engagement insert: $119
- DSP: $26,000
- Legal: $6,500
- Auditors: $6,500
- Total of $39,221 / 5 = $7,844

b) Confirmed.

4.0-VECC-34

Reference: Exhibit 4

a) Is CPUC a member of the EDA? If yes, please provide the annual fee amount paid for membership for the years 2012 through 2019 (forecast).

Responses:

a) Yes

2012 - $5,400.00
2013 - $5,600.00
2014 - $5,800.00
2015 - $5,900.00
2016 - $6,000.00
2017 - $6,100.00
2018 - $6,100.00
2019 - $6,100.00

4.0 -VECC –35

Reference: Exhibit 4, pdf pg. 79

a) CPUC explains that it outsources its LEAP funding to the United Way – Sudbury. Does CPUC know how much of its LEAP funding (shown in Table 39) was accessed in the community of Chapleau? Is yes please explain if the total allotment of LEAP funding was exhausted in each of the past 4 year.

Responses:

a) Yes it's accessed in the community of Chapleau. In the past 4 years only in 2018 was it not exhausted.

4.0-VECC-36

Reference: Exhibit 4, Table 43

a) The third paragraph below Table 43 states: “*None of the estimated CDM load reductions were factored into the load forecast underpinning CPUC's 2011,2012,2013, 2014, 2015,2016 and 2017 rates*.” If this is the case, what is the basis for the Forecast amounts included in Table 43?

Responses:

a) What CPUC is trying to say in the above statement is that the Load Forecast on which the last Board Approved rates were approved did not include savings from 2011 to 2017. For this reason, CPUC is applying for recoveries of LRAMVA form all the above noted years including persistence.

Exhibit 5

5-Staff-61

Ref: Exhibit 5 – Cost of Capital
Revenue Requirement Work Form
OEB Letter of November 22, 2018 for Updated Cost of Capital Parameters for 2019

Preamble:

The OEB issued updated cost of capital parameters applicable for rate applications to rebase rates effective in the 2019 rate year by way of a letter issued November 22, 2018.

Question:

a) Please update CPUC's cost of capital exhibits, the RRWF, and applicable appendices to reflect the 2019 cost of capital parameters and responses to applicable interrogatories by OEB staff and other parties.

Responses:

a) CPUS has updated its Cost of Capital parameters to reflect the November 22 letter.

Cost of Capital Parameter	Value for Applications for rate changes in 2019
ROE	8.98%
Deemed LT Debt rate	4.13%
Deemed ST Debt rate	2.82%

5.0-VECC-37

Reference: Exhibit 5

a) Please provide the achieved ROE for 2018.
b) Is the achieved ROE in 2016 positive or negative 3.82%?

Responses:

a) This information will not be available until mid April at the earliest CPUC commits to providing this information when available.
b) CPUC cannot confirm this information until the ROE is calculated

5.0-VECC-38

Reference: Exhibit 5

a) Please update the cost of capital evidence (Appendix 2-OA and RRWF) for the cost of capital parameters established by the Board in their letter of November 22, 2018.

Responses:

b) Please see CPUC's response to 5-Staff-61.

5.0-VECC-39

Reference: Exhibit 5

a) Does CPUC have any short-term debt (including lines of credit)? If yes, please describe the amounts, interest rate(s) and issuer.
b) Does CPUC finance its entire capital budget from retained earnings?
c) Please explain what project(s) in the DSP are being referred to what CPUC believes will require it to obtain long-term debt to finance? What is the amount of the investment contemplated and for when?

Responses:

a) CPUC does not have any short-term debt.
b) CPUC confirms that it finances its capital budgets from retained earnings.
c) Please refer to CPUC's response to 2-Staff-23.

Exhibit 7

7-Staff-62

Ref: Exhibit 7, Weighting Factors

Preamble:

CPUC has calculated cost per connection to bill all rate classes and divided that by connection count to arrive at a cost per connection to bill and collect from each rate class. The cost is then used to determine costs relative to residential (which is assigned a weight of 1.00). However, billing and collecting factors are applied on the number of bills, which is typically the number of customers times 12.

Questions:

a) Please confirm that the weighting factors are calculated on the number of connections.

b) Please prepare a weighting factor based on the number of bills.

Responses:

a) Confirmed.

b) Please see below. Note that with the exception of streetlighting, the ratio between both scenarios are the same. CPUC confirms that its original weighting factors are more accurate with respect to Street Lighting.

2017						
Accounts 5305 - 5340		1221	1237			
	Residential	**GS < 50**	**GS > 50**	**Street Lighting**	**Sentinel Lighting**	**USL**
# of Connections	1065	156	16	328	23	4
# Bills	12397	1782	183	12	276	48
N.Harris Computer Corporation	*1,725.35*	*252.73*	-	-	-	-
Sensus Canada Inc.	*33,389.30*	*4,890.83*	-	-	-	-
Payroll related to lrg user meter reads			*769.08*			
Bad Debt	*5,127.71*	*558.36*	*81.34*	-	-	-
5315 - Customer Billing	53,785.92	7,878.50	808.05	16,565.05	1,161.57	202.01
Total	94,028.28	13,580.42	1,658.47	16,565.05	1,161.57	202.01
Cost Per Connection	88.29	87.05	103.65	50.50	50.50	50.50
Cost Per Bill	7.58	7.62	9.07	1,380.42	4.21	4.21

Weighting (Residential set as standard)	1.00	0.99	1.17	0.57	0.57	0.57
Weighting (Using # bills)	1.00	1.01	1.20	182.00	0.55	0.55
Ratio between WF per customer vs per bill		0.98	0.98	0.00	1.03	1.03

7-Staff-64 Scale Load Profiles using LF do not update model

Ref: Exhibit 7, Load Profiles; Cost Allocation Model
2012 Cost of Service Cost Allocation Model[17]

Preamble:

CPUC has used the demand allocators from its cost allocation model filed with its 2012 Cost of Service rate application in its current cost allocation model. It explains that it "believes that its customer count and load has not changed dramatically enough to warrant an update of the demand data in the absence of the core file needed to do so."

Questions:

a) Please confirm that this approach would not reflect any differences in growth rates between the rate classes.

b) Has CPUC considered scaling the demand allocators from 2012 based on the change in load from the 2012 forecast underpinning those demand allocators to the proposed 2019 load forecast?

   i. Has CPUC considered any other methods of updating the demand allocators to be consistent with the 2019 load forecast?

c) Please prepare a cost allocation run where the demand allocators have been scaled to be consistent with 2019 forecasted load.

d) Please confirm that CPUC will begin to gather the meter data required to prepare new load profiles for its next cost of service rate application.

Responses:

a) Confirmed. CPUC reiterates that its classes have not been subject to a significant growth rate since 2012.

b) CPUC did not consider the option of scaling the demand allocators from 2012 based on the change in Load Forecast.

c) See the requested profiles below.

[17] EB-2011-0322

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Lighting	8 Sentinel	9 USL
		CP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	6,894	3,838	1,403	1,626	24	2	0
Bulk Delivery CP	BCP1	6,894	3,838	1,403	1,626	24	2	0
Total Sytem CP	DCP1	6,894	3,838	1,403	1,626	24	2	0
4 CP								
Transformation CP	TCP4	25,521	14,238	5,362	5,815	97	8	2
Bulk Delivery CP	BCP4	25,521	14,238	5,362	5,815	97	8	2
Total Sytem CP	DCP4	25,521	14,238	5,362	5,815	97	8	2
12 CP								
Transformation CP	TCP12	57,112	30,648	12,177	14,001	263	17	4
Bulk Delivery CP	BCP12	57,112	30,648	12,177	14,001	263	17	4
Total Sytem CP	DCP12	57,112	30,648	12,177	14,001	263	17	4
NON CO_INCIDENT PEAK								
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP								
Classification NCP from Load Data Provider	DNCP1	7,611	4,218	1,565	1,747	72	9	0
Primary NCP	PNCP1	7,611	4,218	1,565	1,747	72	9	0
Line Transformer NCP	LTNCP1	7,611	4,218	1,565	1,747	72	9	0
Secondary NCP	SNCP1	7,611	4,218	1,565	1,747	72	9	0
4 NCP								
Classification NCP from Load Data Provider	DNCP4	27,815	15,294	5,874	6,328	287	31	2
Primary NCP	PNCP4	27,815	15,294	5,874	6,328	287	31	2
Line Transformer NCP	LTNCP4	27,815	15,294	5,874	6,328	287	31	2
Secondary NCP	SNCP4	27,815	15,294	5,874	6,328	287	31	2
12 NCP								
Classification NCP from Load Data Provider	DNCP12	62,550	32,708	13,552	15,352	861	72	4
Primary NCP	PNCP12	62,550	32,708	13,552	15,352	861	72	4
Line Transformer NCP	LTNCP12	62,550	32,708	13,552	15,352	861	72	4
Secondary NCP	SNCP12	62,550	32,708	13,552	15,352	861	72	4

d) CPUC gathered three years worth of hourly data and had started its attempt to update its Load Profile using hourly data. However, upon reviewing London Hydro's failed attempt to update its profiles, CPUC determine that it did not have enough background information on Hydro One's original methodology and did not have enough time or resources to present, support and defend new profiles using hourly data.

7-Staff-65

Ref: Cost Allocation Model

Preamble:

OEB staff notes that CPUC has populated the cost allocation model with the Unmetered Scattered Load (USL) rate class in column number 7. In the blank 2019 cost allocation model, this column is labelled “Street Light”, and is intended to be used for the street light rate class. By populating this column with USL, the Street Light Adjustment Factor (SLAF) has now been applied to the USL rate class, and not to the street lighting rate class.

The number of street light devices has been left blank, while the number of street light connections has been populated as 328.

Questions:

a) Please revise the cost allocation model with Street Light populated in column 7, and USL populated in column 9.

b) Please confirm that there are 328 street light devices, and that each one is directly connected to the distribution system. If not, please revise the model to supply both the number of street lighting devices, and the number of connections to the distribution system.

Responses:

a) The model has been revised to resolve this issue.

b) CPUC confirms that is has 328 streetlights and that each is connected to the DS.

7-Staff-66

Ref: Cost Allocation Model sheets I6.1 Revenue; I8 Demand Data
RRWF sheet 13. Rate Design

Preamble:

CPUC has not recorded any load as being subject to Transformer Ownership Allowance (TOA) in cost allocation and the RRWF. The demand data in cost allocation indicates that all load is served through CPUC owned transformers and connected to the secondary distribution system.

Questions:

a) Please confirm that all of CPUC's customers are connected at secondary voltages. If not, please explain.

b) Please confirm that there are no customers eligible for TOA. If not, please explain.

Responses:

a) Confirmed.

b) Confirmed.

7-Staff-67

Ref: Cost Allocation Model sheets I6.2 Customer Data; I7.1 Meter Data; I7.2 Meter Reading

Preamble:

CPUC has entered 1033 residential customers on sheet I6.2 Customer Data, 1133 residential meters on sheet I7.1 Meter Capital, and 1033 residential meter reading activities on sheet I7.2 Meter Reading. For GS > 50, CPUC has entered 15 customers on sheet I6.2 Customer Data, 12 meters on sheet I7.1 Meter Capital, and 12-meter reading activities on sheet I7.2 Meter Reading. For the GS < 50 rate class, CPUC has entered 148 on all three worksheets.

Questions:

a) Please explain why CPUC has 100 more residential meters entered than customers or meter reading activities. If this is due to an error, please revise.

b) Please explain why CPUC has 15 GS > 50 customers, but only 12 meters for these customers. If this is due to an error, please revise.

Responses:

a) The 1133 was a result of an input error. Sheet I7.1 should have indicated 1033.

b) Same as response to a) above, this is as a result of an input error. Both sheets have been updated in the model filed with these responses.

7-Staff-68

Ref: Exhibit 7, Table 9
Cost Allocation Model sheet O2 Fixed Charge|Floor|Ceiling

Preamble:

The charges for "Customer Unit Cost per month – Directly Related" and "Customer Unit Cost per month – Minimum System with PLCC Adjustment" do not match between Table 9 and Sheet O2 of the cost allocation model.

Question:

a) Please reconcile the differences.

Responses:

a) Staff is correct. Table 9 did not match Sheet O2 of the Cost Allocation model. The results at tab O2 of the Cost Allocation filed along with these responses have changed since the application. The revised results are shown below.

	1	2	3	7	8	9
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Lighting**	**Sentinel**	**USL**
Customer Unit Cost per month - Avoided Cost	$11.94	$9.24	$9.77	$0.01	$3.37	$3.37
Customer Unit Cost per month - Directly Related	$24.54	$21.26	$20.40	$0.02	$7.78	$7.78
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$35.43	$32.22	$32.96	$0.64	$20.08	$20.08
Existing Approved Fixed Charge	$24.04	$35.18	$193.66	$4.43	$8.65	$24.99

7-Staff-69

Ref: Exhibit 7, Revenue-to-Cost Ratios
RRWF sheet 11. Cost_Allocation
Filing Requirements, page 49[18]

Preamble:

CPUC is proposing to decrease the USL revenue-to-cost ratio from 376.62% to 250.1% in 2019. It proposes to do this by increasing the revenue-to-cost ratios for residential from 93.38% to 93.40%, and Sentinel from 91.3% to 100.91%. According to Table 15 in Exhibit 7, CPUC proposes further decreases to the USL revenue-to-cost ratio to 160% in 2020, and 120% in 2021, and has not proposed any rate classes to make up the shortfall. However, in the RRWF on sheet 11. Cost Allocation, CPUC is proposing that revenue-to-cost ratios for all rate classes remain at 2019 levels through 2020 and 2021.

The Filing Requirements state "if the proposed ratios are outside the OEB's policy range in the test year, the distributor must show the proposed ratios in subsequent years that would move the ratios to within the policy range." The Filing Requirements also state "Applicants are also reminded of the OEB's policy that revenue-to-cost ratios should not be moved away from unity." However, CPUC is proposing to increase the Sentinel light revenue-to-cost ratio above unity when the residential rate class remains below unity.

Questions:

a) Please confirm that CPUC is proposing to have all revenue-to-cost ratios within the range by 2021 or explain why not.

b) If CPUC is proposing continued adjustments to the revenue-to-cost ratios after 2019, please provide the resulting revenue-to-cost ratios for all classes indicating where shortfall will be recovered.

Responses:

a) Table 15 of Exhibit 7 or Appendix 2-P clearly shows the adjustments post 2019.

b) Please see table below. Note that results and adjustments have been revised to factor in the responses to these IRs.

[18] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service, July 12, 2018

##	#	#	#	5353#	#	5354#	#	5355#	#
#Fxvwrphu#Fodvv#Qdph#	Fdofxodwhg# U2F#Udwlr#	Sursrvhg# U2F# Udwlr#	Vkruwidoo# Uhfrqfldwlrq#	Sursrvhg# U2F#udwlr#	Uhyhqxh# Uhdoorfdwlrq#	Sursrvhg# U2F#udwlr#	Uhyhqxh# Uhdoorfdwlrq#	Sursrvhg# U2F#udwlr#	Uhyhqxh# Uhdoorfdwlrq#
Uhvlghqwldo#	31<3#	31<4#	('</5;<1:5#	31<6#	('4;/373159#	31<7#	('59/:<31:<#	31<8#	('68/:84167#
Jhqhudo#Vhuylfh#?#83#nZ #	414:#	414:#	'<71<7#	414:#	'<71<7#	414:#	'<71<7#	414:#	'<71<7#
Jhqhudo#Vhuylfh#A#83#wr#7<<<#nZ #	4139#	4138#	'8:4194#	4138#	'8:4194#	4138#	'8:4194#	4138#	'8:4194#
Xqphwhuhg#Vfdwwhuhg#Orrdg#	4195#	41;3#	('4:5134#	41;3#	('4:5134#	41;3#	('4:5134#	41;3#	('4:5134#
Vhqwlqho#	31;5#	31;5#	('61;6#	31;5#	('61;6#	31;5#	('61;6#	31;5#	('61;6#
Vwuhhw#Oljkwlqj##	9157#	71<;#	';/:<<134#	61:6#	'4:/87<187#	517;#	'59/63313;#	4153#	'68/593196#

7.0 – VECC –40

Reference: Exhibit 7, Table 3

a) The table heading suggests that the activities relate to Accounts 5305-5340. However, according to Tab E1 of the Cost Allocation Model, the Billing and Collecting Weighting factor is not used for Accounts 5310 and 5335. Please reconcile.
b) Please describe the services provided by each of Harris Computer Corporation and Sensus Canada Inc. and explain: i) how they are related to billing and collecting and ii) why they are only associated with the Residential and GS<50 classes.
c) Please explain why Bad Debt is included in the determination of the weighting factors when it has a separate allocator.
d) In Table 3, how was the cost of Customer Billing assigned to customer classes?
e) Please reconcile the total costs as set out in Table 3 with the costs in the Cost Allocation Model (Tab I3) for accounts 5305, 5315, 5320, 5325, 5330, and 5340 (i.e., the accounts to which the allocation factor is applied)

Responses:

a) The table heading is meant to describe the Billing and Collecting accounts or 5305-5340. The specific accounts are shown in the rightmost column in the table below.

b) i)Sensus Canada – They read hourly every customer's meter and submit the data daily to the Smart Meter Entity and they submit daily reports to Chapleau PUC.

Harris Computer Corp. – They are our metering data storage, which is an OEB requirement. Sensus only stores meter data for two months, where as Harris stores is forever.

ii) Sensus and Harris are related to meter reading, Residential and GS<50 are the only classes that need hourly reads.

2017								
Accounts 5305 - 5340		1221	1237					
	Residential	**GS < 50**	**GS > 50**	**Street Lighting**	**Sentinel Lighting**	**USL**	**Total Annual Cost**	**Acct**
# of Connections	1065	156	16	328	23	4	**1592**	
N.Harris Computer Corporation	*1,725.35*	*252.73*	-	-	-	-	*1,978.08*	*5310*
Sensus Canada Inc.	*33,389.30*	*4,890.83*	-	-	-	-	*38,280.13*	*5310*
Payroll related to lrg user meter reads			*769.08*				*769.08*	*5310*
Bad Debt	*5,127.71*	*558.36*	*81.34*	-	-	-	*5,767.41*	*5335*
5315 - Customer Billing	53,785.92	7,878.50	808.05	16,565.05	1,161.57	202.01	80,401.11	5315
Total	53,785.92	7,878.50	808.05	16,565.05	1,161.57	202.01	80,401.11	
Cost Per Connection	50.50	50.50	50.50	50.50	50.50	50.50		
Weighting (Residential set as standard)	1.00	1.00	1.00	1.00	1.00	1.00		

c) .

d) Table 15 of Exhibit 7 or Appendix 2-P clearly shows the adjustments post 2019.

e) VECC is correct in Bad Debt has its own allocator however CPUC does not see any reason why it should be excluded from the weighting factors for billing and collecting.

f) CPUC used the customer count as a weighting factor when allocating the balance of 5315 to each class.

g) CPUC used 2017 actuals, which are more accurate than projections, to determine the weighting factors in Table 3 of Ex 7 therefore the costs cannot be matched to 2019 projected costs at tab I3.

7.0 – VECC –41

Reference: Exhibit 7, Cost Allocation Model, Tab I6.2 (Customer Data)

a) Why is there no USL customer count for Primary Customer Base or the Line Transformer Customer Base?

Responses:

a) CPUC believes that it inadvertently used the column intended for the Street Lighting for the USL class. The model filed with these responses has been updated.

7.0 – VECC –42

Reference: Exhibit 7, Table 15

a) Why is the revenue shortfall from reducing the USL R/C ratio all being assigned to the Sentinel class?

b) With respect to Section D of Table 15, do the proposed R/C ratios for any of the other customer classes change in either 2020 or 2021 as result of the further adjustments to the USL ratio?

Responses:

a) The premise of the question is incorrect. The shortfall of $600 is absorbed between both classes that are under the midpoint of 1.00. Because the bill impacts for the residential class is more critical for CPUC, the utility did allocate $265 more to the residential class for the purpose of keeping it as close as possible to its original R/C ratio of 0.9338 (as applied for in Aug 2018).

b) See table below (Using data as applied for in August of 2018)

2019		2020		2021	
Proposed R/C ratio	Revenue Reallocation	Proposed R/C ratio	Revenue Reallocation	Proposed R/C ratio	Revenue Reallocation
0.9341	-213.2	0.9345	-449.2	0.9350	-827.7
1.1999	75.6	1.1999	75.6	1.1999	75.6
1.0605	19.0	1.0605	19.0	1.0605	19.0
2.4987	599.9	2.0000	835.9	1.2000	1,214.5
1.0091	-478.7	1.0091	-478.7	1.0091	-478.7
1.11	9	1.11	9	1.11	9

Exhibit 8

8-Staff-70

Ref: Exhibit 8, section 8.1.2
Exhibit 8, section 8.1.16
RRWF sheet 12. Res_Rate_Design

Preamble:

CPUC is proposing increase the residential fixed charge from $24.04, to $50.87. This reflects an increase of $6.79 to $30.83 to recover the deficiency, and an increase of $20.04 to $50.87 to implement the residential rate design policy in a single year. CPUC reasons that the Distribution Rate Protection Plan (DRP) will limit the charge to $36.86. OEB staff notes that following this reasoning, residential rate design would increase the fixed charge from $30.83 to the maximum imposed by the DRP of $36.86. Therefore, a residential customer would be exposed to an increase in the fixed charge of $6.03). This is still in excess of the $4.00 threshold. If CPUC were to commence a five-year transition in this application, the fixed charge would increase by $4.01 to $34.84 as a result of the residential rate design policy.

CPUC has provided a residential bill impact scenario for 405 kWh of energy consumption to address the 10th percentile of consumption. In arriving at the 10th percentile of consumption, CPUC has filtered out all customers that had less than 12 months of consumption, and those that used less than 50 kWh per month.

OEB staff has calculated that a five-year transition would result in a variable charge of $0.0144/ kWh, and that at 405 kWh, this would result in a variable charge of $5.83. Combined with the $34.84 fixed charge under that scenario, the total charge from base rates would be $40.67. Since this is more than $36.86, the selection of a one-year transition or five-year transition would have no impact on the total bill of a low-volume residential customer after DRP has been applied.

Questions:

a) Has CPUC considered starting a five-year transition to fully fixed rates in this rate application with the possibility of accelerating the transition once the DRP contains the increase in fixed charge (as seen by the customer) to $4.00?

b) In arriving at the 10th percentile of consumption, why did CPUC filter out customers that had less than 50 kWh per month?

c) Please confirm or correct OEB staff's calculation of the impact of a five-year transition to fully fixed rates.

Responses:

a) CPUC tested and considered various scenarios in arriving to a rate design that is acceptable. CPUC is also aware that the rated design exercise needs to be revisited throughout the application process right up until the decision is issued before a specific rate design can be approved.

8-Staff-71

Ref: Exhibit 8, section 8.1.4
RTSR Model sheet 5. UTRs and Sub-Transmission
Decision and Interim Rate Order, December 20, 2018[19]

Preamble:

CPUC has used the 2018 UTRs for 2019. The 2019 UTRs were released in the Decision and Interim Rate Order referenced, and are as follows:

Network:	$3.71
Line Connection:	$0.94
Transformation Connection:	$2.25

Questions:

a) Please update the RTSR model with the current UTRs.

Responses:

a) CPCU notes that the 2018 UTRs were the most recent rates at the time of the filing August 31, 2018. CPUC has updated its RTSRs rates to reflect the 2019 rates published on December 20, 2018.

[19] EB-2018-0326

8-Staff-72

Ref: Exhibit 8, section 8.1.11

Preamble:

CPUC states:

> The 2018-2019 estimates of total LV charges were calculated based on the last year of actual charges from Hydro One. The reason for using 2016 is that Hydro One's LV charges increased considerably in 2016 compared to 2015 and previous years, such that the utility felt that using 2016 would be more appropriate.

OEB staff notes that the $68,999 sought for recovery is equal to a four-year average of 2014-2017. In the first three of those four years, the charge was over $70,000 in each year, and in 2017, the charge was $59,187.

Questions:

a) Please confirm that CPUC is actually proposing to use a four-year average of 2014-2017 LV charges.

b) Please explain the cause of the decrease in LV charges in 2017.

c) Please provide the 2018 LV charges.

Responses:

a) In its application filed on August 31, 2018, CPUC proposed using an average of 4 years.

b) In 2013-2015 there was a Low Voltage Adjustment added due to a Hydro One billing error.

c) LV charges for 2018 are in the amount of $38,844.95

8-Staff-73

Ref: Exhibit 8, section 8.1.12
Chapter 2 Appendices Appendix 2-R
RTSR Model
2015 IRM Decision and Rate Order March 19, 2015[20]

Preamble:

CPUC states that it proposes a Total Loss Factor (TLF) of 1.0500 using the historical average of the last five years. However, CPUC did not complete Appendix 2-R, instead, it completed a standalone worksheet on the basis of a six-year average, which indicates a loss factor of 1.0757.

CPUC states that the proposed loss factor “represents a decrease from the currently approved loss factor of 1.0757.” However, the currently approved loss factor is 1.0654, so the calculated loss factor is an increase.

CPUC states that “As an embedded distributor to Hydro One Networks Inc. (“HONI”) CPUC uses the standard SFLF of 0.0034.” However, Chapter 2 Appendix 2 Appendix 2-R explains that “If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340.” Appendix 2-R also explains that “if partially embedded, SFLF should be calculated as the weighted average of above.” This is in reference to the Hydro One loss factor of 1.0340 and the IESO controlled grid loss factor of 1.0045.

In the RTSR model, CPUC has recorded billing quantities for both the IESO and Hydro One. This implies that CPUC is not fully embedded, it is partially embedded.

Questions:

a) Please clarify whether CPUC is fully embedded or partially embedded in Hydro One.

b) Please explain why CPUC decided to prepare a loss factor calculation on the basis of a six-year average instead of the standard five-year average.

c) Please revise Appendix 2-R using a supply facility loss factor of 1.0340 for Hydro One or explain why the lower loss factor should be used.

d) If CPUC is fully embedded in Hydro One’s service area, please revise the RTSR model.

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[20] EB-2014-0063

e) If CPUC is partially embedded in Hydro One's service area, please prepare Appendix 2-R using a weighted average of the loss factors for Hydro One, and the IESO controlled grid.

f) Please explain the drivers that have led to the increased loss factor as compared to the previous approved 1.0654.

Responses:

a) CPUC purchases its power from both Hydro One and the IESO.

b) Given that it has been 7 years since its last Cost of Service, CPUC felt it was appropriate to go back to 2012 to determine its loss factor.

c) The 0.0034 was an error and should have been 0.034. The loss factor used in the revised Rate Base and Revenue Requirement uses the revised facility loss factor of 0.034.

d) See response to a).

e) The possible reasons for the losses and recommendation for upgrades are discussed in detail in CPUC's Utility Load Flow and Substation Evaluation, Capacity and Redundancy Study conducted by Metsco in June of 2018. The report is part of the utility's DSP at Exhibit 2.

8-Staff-74

Ref: Exhibit 8, section 8.1.16
Exhibit 8, section 8.1.17

Preamble:

In reference to the OEB's policy requiring mitigation of total bill impacts over 10%, CPUC notes that "several classes exceed the 10% namely the Residential class at the 10th percentile threshold, Street Lighting and Sentinel Lighting." It explored lengthening the disposition period of rate riders and found that not to be a suitable means of mitigation.

CPUC proposes "to explore, during settlement, deviating from Board policy with respect to adjustments to the revenue/costs ratios and fixed to variable. As an additional form of rate mitigation, CPUC proposes to extend the implementation of the fixed rate design for the residential class if necessary."

Question:

a) Please explain CPUC's ideas for how changes to the fixed and variable split might be used to manage the bill impacts.

Responses:

a) The question implies that the OEB is not aware of a correlation between the fixed to variable charge and bill impacts.
CPUC has pasted an excerpt of the OEB's Distribution Rate Design Policy to support its point that both the fixed to variable split and the revenue to cost ratios play a role in determining bill impacts.

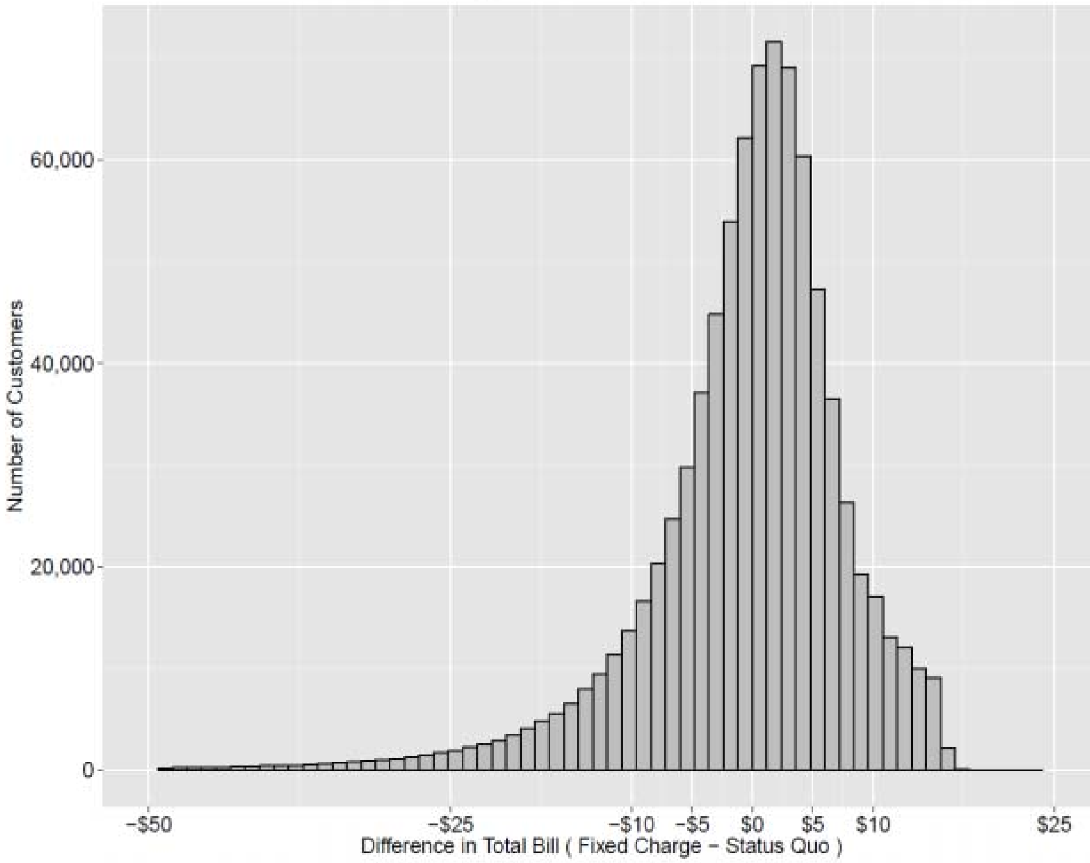
Customer Impacts

The result of the distribution rate design change will be that the distribution portion of all residential customer bills will be stable and predictable. All residential customers of a particular distributor (for example, Toronto Hydro or Hydro Ottawa) will pay the same monthly distribution charge. These charges will not vary with the weather, so distributors will no longer earn extra revenue (or have a revenue shortfall) as a result of weather differences.

The impact on a customer's bill, however, will vary depending upon how much electricity they use: higher volume customers will pay lower distribution charges than they currently pay, and lower volume customers will pay higher distribution charges than they currently pay. We analyzed the bill impact for the residential customers on eleven distribution systems, or about 850,000 customers. Figure 1 below shows that most customers will see little change in their total bill after the new policy is fully implemented:

- About 57% of customers will see no change, or will see a bill increase or decrease of less than $5 per month.
- About 21% will see a bill decrease of more than $5 per month.
- About 22% will see an increase of more than $5 per month.

Figure 1: Bill Impacts for all Residential Customers of 10 Distributors ($ per month)[12]



While most customers will see little or no change, and some customers will see substantial reductions, there will be customers facing bill increases. The OEB understands that bill increases are never welcome. We work to ensure that customers understand the reasons for the increases. It is important that changes are made gradually to mitigate the impact of the increase and to give customers the opportunity to adapt. For this reason, we will implement the new rate design over four years. There is more information about the transition process at the end of this report. Some low volume customers live in multi-unit buildings where the distributor meters each customer individually. We will consider whether these customers should be charged a separate rate. At the end of this report we explain how that issue will be examined.

8-Staff-75

Ref: Exhibit 8, Appendix A Existing Tariff Sheet
Exhibit 8, Appendix B Proposed Tariff Sheet
Exhibit 8, Appendix C Bill Impacts
Chapter 2 Appendices, Appendix 2-R

Preamble:

CPUC's existing tariff sheet has a secondary loss factor of 1.0654, and a primary loss factor of 1.0506. The proposed tariff sheet has secondary and primary loss factors both at 1.0757. The bill impacts use a loss factor of 1.0500 for both current and proposed.

CPUC's residential bill impacts all include an adjustment to reflect the impact of the DRP.

Questions:

a) Please confirm that CPUC is proposing to apply the same loss factor to primary and secondary customers where it previously applied different loss factors.

   i. If so, please provide the rationale.

   ii. If not, please revise.

b) Please revise the bill impacts to that it is consistent with the existing and proposed loss factors.

c) Please also revise the tariff sheets and bill impacts, consistent with the filing requirements and OEB policy for any changes to CPUC's application arising from the interrogatory phase.

d) Please provide versions of the residential bill impacts that omit the DRP adjustment.

Responses:

a) CPUC has calculated the secondary loss factor only. It is CPUC's understanding that the OEB applies the appropriate adjustment from primary to secondary. CPUC notes from pervious application and draft rate order that 0.104 may be subtracted from the secondary to get to the primary. CPUC notes that there are no customers connected to the primary service.

b) A revised version of the bill impact and tariff sheet has been filed along with these responses.

c) See response to b) above.

d) The DRP is embedded in the OEB model therefore CPUC cannot produce bill impacts without the DRP at this time.

8-Staff-76

Ref: CPUC 2018 IRM application[21]
Exhibit 8, page 35
Exhibit 9, page 51
Exhibit 1, page 33
Exhibit 1, page 120

Preamble:

At the first noted reference, OEB staff notes that CPUC filed a 2018 IRM application[22] on February 9, 2018. On April 27, 2018 rates were declared interim effective May 1, 2018. In its interim rate order, the OEB stated that further procedural steps in the 2018 IRM proceeding would not be set until a determination was made with respect to CPUC's May 16, 2017 request to defer its cost of service rate application. On August 14, 2018,[23] the OEB stated that it expected CPUC to file a 2019 cost of service application. In this letter, the OEB also stated that CPUC's 2018 IRM application will be dealt with by the OEB Panel that hears CPUC's 2019 cost of service application.

At the second noted reference, CPUC stated the following:

> CPUC notes that it may need to establish a foregone revenue rider to address the 2018 IRM application filed in February of 2018 and is still pending.

At the third noted reference, CPUC stated the following:

> …CPUC notes that it may be necessary to create a foregone revenue [deferral account] to capture the revenue increase from the 2018 IRM application.

At the fourth noted reference, CPUC stated the PEG Target Performance (Stretch Factor) for 2018 and 2019 is expected to be in Group 5, which implies a decrease in efficiency. At the fifth noted reference, CPUC stated that it has been assigned a Group 4 efficiency ranking since 2013.

OEB staff notes that CPUC requested the following in its 2018 IRM application:

- a Price Cap Adjustment increase of 1.45%, reflecting an inflation factor of 1.9%, a productivity factor of 0.00%, and a stretch factor of 0.45%
- a transition of its residential customers to a fully fixed rate, with the 2018 rate year being the first year of a four-year period of rate adjustments
- updated RTSRs
- disposal of some of its DVA balances

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[21] EB-2017-0337
[22] EB-2017-0337
[23] EB-2018-0087

- a tax change rate rider

However, OEB staff notes that for the 2018 rate year, the OEB approved an inflation factor of 1.2%,[24] and not 1.9%. In the OEB's August 23, 2018 letter to electricity distributors, CPUC was not included in the group of distributors that had moved either to a higher or lower cohort for the determination of 2018 stretch factor rankings. CPUC's current stretch factor is 0.45% and in Group IV.[25]

Questions:

a) Please calculate the amount of foregone revenue that CPUC is proposing to recover via a foregone revenue rider in this proceeding to address the 2018 IRM application. Please show details of the calculation of this rider.

b) OEB staff notes that the balance relating to recovery of a foregone revenue rider or foregone revenue deferral account may be immaterial, with an inflation factor of 1.2% and a stretch factor of 0.45% applied to its most recently approved rates in 2015 IRM. Please confirm and explain whether the recovery of foregone revenue may be immaterial, due the fact that components of the IRM adjustment may involve both a low inflation rate and a high stretch factor. A high stretch factor may be assigned due to a Group IV efficiency ranking that may apply to CPUC.

Responses:

a) CPUC cannot provide detailed calculations of the foregone rate rider as the final rates and fixed to variable split have yet to be determined. However, subject to OEB approval, CPUC intends on applying a 0.75% (1.20%-0.45%= 0.75%) adjustment to the final Board Approved rates.

b)

Board Staff is implying that utilities in the PEG group 4 or 5 should forgo any IRM adjustment due to its immateriality of the adjustment. CPUC notes that this applies not only to CPUC but also to the following utilities; *Atikokan Hydro Inc., Canadian Niagara Power Inc., Festival Hydro Inc., Hydro One Networks Inc. Hydro Ottawa Limited, Midland Power Utility Corporation, Peterborough Distribution Incorporated, PUC Distribution Inc., Thunder Bay Hydro, Wellington North Power Inc., Algoma Power Inc., Toronto Hydro-Electric System Limited and West Coast Huron Energy Inc.*

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[24] November 23, 2017 entry on the OEB's 2018 EDR webpage

[25] Empirical Research in Support of Incentive Rate-Setting: 2016 Benchmarking Update Report to the Ontario Energy Board, July 2017, prepared by Pacific Economics Group Research LLC

CPUC has calculated its foregone revenues related to its 2018 IRM to be in the amount of $6,358. CPUC disagrees with Board Staff in that $6,358 is an immaterial adjustment especially for a small utility.

	2015	2018	Diff
Fixed Rate	326,848	381,954	55,106
Variable Rate	202,274	153,526	-48,748
	529,121	535,480	6,358

CPUC intends on using calculations similar to tab 16 Rev2Cost_GDPIPI tab of the IRM to calculate its final rate rider related to the foregone 2018 IRM adjustment.

8-Staff-77

Ref: Exhibit 8, page 23
Report of the Ontario Energy Board, Wireline Pole Attachment Charges, March 22, 2018[26]
CPUC Response [sic] to Staff Clarification on the Notice 20190109.pdf
Decision and Order, Energy Retail Service Charges, February 14, 2019[27]
Exhibit 3, Table 37 – OEB Appendix 2-H

Preamble:

At the above noted first reference, CPUC has presented its proposed specific service charges.

As per the above noted second reference, OEB staff notes that changes in pole attachment charges have been approved for all electricity distributors, as per the new OEB policy issued March 22, 2018. As per the above noted third reference, CPUC also confirmed that invoicing for pole rental is done a yearly basis at year end and that $22.35 was used up to August 31, 2018, $28.09 from September 1, 2018 to December 31, 2018. CPUC is charging $43.63 as of January 1, 2019.

As per the above noted fourth reference, OEB staff notes that the Decision and Order, Energy Retail Service Charges,[28] issued on February 14, 2019 shows changes to specific services charges. The changes to select charges are noted in yellow shading below and a new charge is noted in green shading below. These changes are effective May 1, 2019.

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	$	100.00
Monthly fixed charge, per retailer	$	40.00
Monthly variable charge, per customer, per retailer	$/cust.	1.00
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.60
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.60)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.50
Processing fee, per request, applied to the requesting party	$	1.00
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)	$	4.00
Notice of switch letter charge, per letter	$	2.00

LOSS FACTORS

[26] EB-2015-0304
[27] EB-2015-0304
[28] EB-2015-0304

At the above noted fifth reference, CPUC has presented its Other Revenue calculations. OEB staff notes that Other Revenue is an offset to CPUC's 2019 proposed revenue requirement.

Question:

a) Please update the tariff sheet, Appendix 2-H Other Revenue (including an updated amount to offset the 2019 revenue requirement), and the RRWF to account for the changes in the above noted energy retail service charges and pole attachment charge.

Responses:

a) CPUC does not have any customers with retailers therefore no changes to the Other revenues were required. CPUC commits to updating its final tariff sheet with the mandated rates upon the final Decision and Order

8-Staff-78

Ref: Tariff sheet, CPUC Tariff Sheet 20190701.pdf
Letter from the OEB, OEB's Plan to Standardize Processes to Improve Accuracy of Commodity Pass-Through Variance Accounts, July 20, 2018

Preamble:

OEB staff notes that CPUC's tariff sheet includes a reference to the Debt Retirement Charge (DRC), however the DRC has ended for all electricity users.

OEB staff notes that updated wording may be included in the "Application" section of the rate class "General Service 50 to 4,999 kW Service Classification." The following two paragraphs may be inserted in the tariff sheet for this rate class. These two paragraphs may be inserted after the paragraph in the Application section of the tariff sheet beginning with the phrase "Unless specifically noted…"

- 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 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 non-RPP Class B customers.

As per the July 20, 2018 letter from the OEB referenced above, the following is stated:

> Effective immediately, the OEB will not be approving Group 1 rate riders on a final basis pending the development of this further guidance. Whether the riders will be approved on an interim basis or not approved at all (i.e. no disposition of account balances) will be determined on a case by case basis, until such time as

the OEB has finalized the new standardized requirements for regulatory accounting and RPP settlements.

OEB staff notes that the reference to the deferral and variance account rate riders in the tariff sheet do not include a reference that any DVA rate riders impacting Group 1 DVAs are to be cleared on an interim basis.

Questions:

a) Please remove the references to the Debt Retirement Charge to the tariff sheet.

b) Please update the tariff sheet to reflect the new above wording for the GS > 50 to 4,999 kW rate class.

c) Please update the tariff sheet to show that any DVA rate riders impacting Group 1 DVAs are to be cleared on an interim basis. As a result, the description of these rate riders should include the phrase "Approved on an Interim Basis."

Responses:

a) Reference to the Debt Retirement Charge will be removed from the final tariff sheet.

b) The final tariff sheet will be updated with the suggested wording for the GS > 50 to 4,999 kW rate class.

c) The final tariff sheet will be updated to show that any DVA rate riders impacting Group 1 DVAs are to be cleared on an interim basis.

8-Staff-79

Ref: CPUC Bill Impacts 20190701.pdf
CPUC 2019_Tariff_Schedule_and_Bill_Impact_Model 20190107.xlsb

Preamble:

OEB staff notes that updated bill impacts are required upon completion of all interrogatories.

OEB staff notes that the latest bill impact model submitted by CPUC is incorrect. There are numerous inconsistencies in the bill impact model such as including:

- Incorrect DVA rate riders (as outlined in the deferral and variance account section of OEB staff's interrogatories)
- Incorrect allocation of certain DVA rate riders to some sub-totals of the bill impact calculations
- Incorrect charges (e.g. WMS, RRRP, etc.)
- An incorrect adjustment for the DRP (the DRP credit is overstated by $0.43)

Questions:

a) Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Tariff Schedule and Bill Impact model for all classes, updated to reflect any changes throughout the interrogatory process, at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.).

Responses:

a) An updated version of the Bill Impacts are filed in conjunction with these responses.

8-Staff-80

Ref: Exhibit 8, page 31
Exhibit 1, page 70

Preamble:

At the above noted reference, CPUC has provided a link to its Conditions of Service on its website.

At the above noted second reference, CPUC stated the following:

> CPUC's conditions of service are updated on a regular basis and were last updated in October of 2017. The utility's most recent Conditions of Service are accessible on the utility's website at http://www.chapleau.ca/en/townshipservices/publicutilities.asp. CPUC confirms that that the conditions of service do not purport to establish any charges that are not approved as part of the posted tariff sheet Conditions of Service but that the tariff sheet is posted on the utility's website.

Questions:

a) Please describe any changes made in the Conditions of Service since CPUC's last cost of service application or as a result of the current application.

b) Please confirm that there are no rates and charges included in CPUC's Conditions of Service that do not appear on CPUC's tariff sheet.

Responses:

a)&b) Both of the questions above are addressed in Section 8.1.15 of the application.

8.0 –VECC – 43

Reference: Exhibit 8, Section 8.1.2 and the Bill Impact Model

a) Why is $36.43 used in the DRP adjustment calculation as set out in the Bill Impact Model when according to the Application this value was updated to $36.86 in the spring of 2018?
b) Is there any expectation that this value will be further updated in the spring of 2019?

Responses:

a) The DRP adjustment in the Bill Impact model is calculated automatically. The utility cannot update this value at this time.
b) At this point, CPUC is not aware of an imminent change in the DRP; CPUC expects that the OEB will have updated information with respect to the applicable DRP value for use in this application.

Exhibit 9

9-Staff-82

Ref: DVA Continuity Schedule filed August 31, 2018

Preamble:

Subsequent to the OEB's original posting of the DVA Continuity Schedule on the OEB's website, the OEB has posted a revised model to correct for changes in certain formulas. Formulas have been revised in Tab 7, Column F of the DVA Continuity Schedule. The revised DVA Continuity Schedule is attached as Attachment 1 to OEB staff's interrogatories which contains the required adjustments to CPUC's model filed August 31, 2018.

Question:

a) When making changes to the DVA Continuity Schedule as a result of OEB staff interrogatories, please use the model filed as Attachment 1 to OEB staff's interrogatories.

Responses:

a) CPUC confirms that it has used the DVA Continuity Schedule that was sent as part of the interrogatories.

9-Staff-96

Ref: LRAMVA Workform, Tab 2 (LRAMVA threshold)
2012 CoS application[29] (2012 VECC IRR LRAM Attachment B)

Preamble:

CPUC included an LRAMVA threshold of 919,147 kWh established from its last CoS application in 2012. This threshold is applied as forecast savings from 2011 to 2017.

Questions:

a) Please clarify whether the reference document from the 2012 CoS proceeding "2012 VECC IRR LRAM Attachment B" is the correct document that shows the 919,147 kWh LRAMVA threshold. If not, please provide the specific reference to this number.

b) Please show the detailed breakdown of the composition of the 919,147 kWh LRAMVA threshold approved in CPUC's 2012 CoS.

    a. Did the 2012 LRAMVA threshold include forecast savings amounts in 2011 and 2012 as per the CDM target?

c) In light of the fact that the 2012 LRAMVA threshold of 919,147 kWh was established in the 2012 CoS proceeding, please explain whether or not the threshold of 919,147 kWh has been appropriately applied as forecast savings for 2011. If a correction is required, please revise Table 2-c of the LRAMVA workform to remove the forecast savings included in 2011.

<u>Preamble from 2012 Decision</u>

Excerpt Board Findings on LRAM
Based on CPUC's Reply, the Board is satisfied that the impact of the 2006 and 2007 CDM programs is included in the 2008 forecast, and therefore should not be recovered through its LRAM. The Board directs CPUC to remove any CDM savings from 2006 and 2007 in its calculation of its LRAM. The Board also agrees that the LRAM should not include an estimate of lost revenues for 2011. The Board directs CPUC to remove any CDM savings from 20011 in its calculation of its LRAM.
The Board finds that CPUC shall calculate its interest based on the removal of the pre 2008 CDM savings, the correction for the Great Refrigerator Round-up 2009 - 2010 and excluding 2011 savings.

Responses:

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[29] EB-2011-0322

a) In the absence of any mention of LRAM baseline in the Decision and Order, CPUC confirms that it used the reference document as a baseline.

b) Again, In the absence of any mention of LRAM baseline in the Decision and Order nor a breakdown by class, CPUC used a weighting based on overall consumption per class. Theoretically, CPUC shouldn't use any baseline as none was officially approved by the OEB.

c) In the excerpt above, the Board instructed to that CPUC calculate its interest based on the removal of the pre 2008 CDM savings, the correction for the Great Refrigerator Round-up 2009 - 2010 and excluding 2011 savings. In the absence of any other information relating to the calculations of the baseline, CPUC determines that the 919,147 excludes 2011.

9-Staff-83

Ref: DVA Continuity Schedule, Account 1588 and Account 1589
OEB Letter, Guidance on the Disposition of Accounts 1588 and 1589, May 23, 2017

Preamble:

CPUC has proposed to dispose of a credit amount of $204,757 in Account 1588. On a per customer basis, this balance works out to more than $132 per customer, which appears to be unusually high. This account should have a minimal amount remaining after RPP settlements have been correctly performed with the IESO and are reflected in the utility's General Ledger.

As per OEB's May 23, 2017 letter to distributors titled Guidance on Disposition of Accounts 1588 and 1589, balances proposed for disposition must be trued-up to actuals.

Questions:

a) Please indicate if CPUC has completed all RPP settlement true-ups with the IESO for 2014, 2015, 2016, and 2017.

b) If yes to the previous question, have the RPP true-ups been reflected in CPUC's proposed balances for disposition for Account 1588?

c) Has CPUC reflected true-ups of CT 148 into Accounts 4705 and 4707 (therefore in balances for Accounts 1588 and 1589) based on RPP and non-RPP actual consumption for all of the 4 years for which disposition is sought?

d) Please discuss CPUC's methodology for RPP true-ups for CT 1142 and true-up methodology for GA CT 148 into Accounts 4705 and 4707.

Responses:

a) Yes, CPUC has.

b) Yes, they have.

c) Yes, CPUC has

d) CT1142 from IESO invoice is booked into Account 4705 Power Purchased first and the variance of power purchase and sale of energy is transferred into Account 1588 RSVA Power.

CT 148 from IESO invoice is booked into Account 4705 Power Purchased first. Once this is completed, an analysis is completed to pro-rate the data between 4705 and 4705.100 based on RPP/non-RPP consumption. Once the consumption for the RPP/non-RPP consumption is determined, an allocation is completed to account 4705.100. Any variance of GA charges and GA revenue is transferred into Account 1588.100 RSVA GA.

Monthly, consumption for RPP and non-RPP customers to reconcile the actual consumption vs. the estimated/forecasted consumption. The allocation between RPP and non-RPP is determined based on customers who are billed with TOU – all customers not billed with TOU are determined to be non-RPP customers.

9-Staff-84

Ref: Exhibit 9, page 10
DVA Continuity Schedule Account 1584

Preamble:

On page 10 of Exhibit 9, the evidence states that the amount for disposition is a debit of $8,683. The DVA Continuity Schedule shows a credit of the same amount.

Question:

a) Please clarify and explain the discrepancy.

Responses:

a) There was an error in the drafting of exhibit 9, the evidence should have said “credit”.

9-Staff-85

Ref: Exhibit 9, RCVA Accounts 1518 & 1548
DVA Continuity Schedule

Preamble:

CPUC has requested to dispose of a debit balance of $7,831 in Account 1518. On page 34 of Exhibit 9, CPUC has acknowledged that it has not used Accounts 1548 and 1518 correctly. OEB staff notes that the description of the types of transactions recorded in Accounts appear to be related to Account 1548.

OEB staff notes that according to the APH, only incremental costs (i.e., costs not included in the revenue requirement) of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated with the above these accounts) be recorded in Accounts.

Questions:

a) Please indicate if the balances for disposition should have been recorded in Account 1548 and not in 1518.

b) Please provide a list of revenues and costs including description that were used for calculating variances in these accounts.

c) Please provide evidence as to how the costs in Accounts 5305, supervision, 5315, customer billing and 5340, miscellaneous customer accounting were determined to be incremental.

Responses:

a) CPUC confirms that the balances should have been recorded in 1548.

b) Revenues – The revenues only include Retailer Service Charges
Expenses – invoices from ERTH (application that all retailer transactions go through) for monthly fees and once per year an annual support fee.

c) Cost associated to 1548 are only in account 5315. Total costs for the year are approximately $4k per year.

9-Staff-86

Ref: Exhibit 9, Account 1508 – Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit account (OCEB)
DVA Continuity Schedule
Accounting Procedures Handbook (APH)
OEB Letter, Implementation of the Ontario Clean Energy Benefit (OCEB), January 6, 2011[30]

Preamble:

CPUC is requesting disposition of a debit amount of $32,035 in this account. OEB staff notes that OEB program ended on December 31, 2015.

According to the APH:

> This account shall be used by a distributor to capture the difference between the amounts of reimbursement claimed from the IESO or a host distributor and the financial assistance credited to eligible accounts. This account shall be used by way of exception only; if a licensed distributor cannot adapt its invoices as of January 1, 2011, it will be required to use this variance account for Ontario Clean Energy Benefit purposes.

OEB staff notes that the variance in this sub-account was temporary in nature, and was to be settled with the IESO. As per the OEB letter dated January 6, 2011 on the Implementation of OCEB,

> The Board expects that any principal balances in "Sub-account Financial Assistance payment and Recovery Variance – Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

Questions:

a) Given that OCEB sub-account was temporary in nature, only until the utilities adapted their invoices, and the principal balances were to be settled directly with the IESO, why does CPUC have balance in this account?

b) Why did CPUC not settle the amounts on OCEB through its monthly settlement process with the IESO before the program ended on December 31, 2015?

Responses:

[30] EB-2011-0009

a) The OEB is correct in that this account should not contain any balances. CPUC has removed the balance from the true balance in that account should be 479.37) DVA continuity schedule.
b) CPUC should have and has now corrected the issue.

9-Staff-87

Ref: Exhibit 9, Account 1508 – Sub-account OREC
DVA Continuity Schedule
OEB Letter, Implementation of the Ontario Rebate for Electricity Consumers, February 9, 2017

Preamble:

OEB staff notes that CPUC has stated that it has complied with the OEB letter dated February 9, 2017. However, the excerpt quoted by CPUC clearly indicates that that OREC account was available to the distributors only if they were not able to adapt their invoices by January 1, 2017, and only until the date on which compliant invoices are first issued, but no later than July 1, 2017.

The excerpt also indicates the balance should clear to zero on which the compliant invoices are first issued.

Question:

a) Why does CPUC have a debit balance of $25,025 for disposition for this sub-account?

Responses:

a) CPUC confirms that there was an error in the DVA continuity schedule. The issue has been rectified in the model filed along with these responses.

9-Staff-88

Ref: Exhibit 9, Account 1508 – Sub-account DRP
DVA Continuity Schedule
OEB Letter, Accounting Guidance related to Implementation of *Fair Hydro Act, 2017*, October 31, 2017

Preamble:

CPUC has requested disposition of a credit balance of $176 in this account. The credits provided to the customers should be claimed from the IESO through monthly settlements. CPUC appears to not have followed the OEB guidance for DRP.

On October 31, 2017, the OEB provided accounting guidance related to implementation of *Fair Hydro Act, 2017*. This guidance letter, in part stated the following:

> DRP and FNDC-related transactions will not affect the amounts recorded in a distributor's expenses, revenues or variance accounts.

Question:

a) Please explain the variance recorded in this sub-account.

Responses:

CPUC confirms that there was an error in the DVA continuity schedule. The issue has been rectified in the model filed along with these responses.

9-Staff-94

Ref: Exhibit 9 – Overall Process and Procedural Controls over the IESO Settlement Process (p. 51)
OEB letter, Accounting Guidance related to Accounts 1588 RSVA Power, and 1589 RSVA Global Adjustment, February 21, 2019

Preamble:

OEB staff notes that Fit/MicroFit should affect settlements with the IESO.

Questions:

a) Please clarify what does CPUC mean by:

> CPUC does not have its own embedded generation. However, CPUC does have Fit/MicroFits.

b) Please review the accounting guidance issued by the OEB on February 21, 2019 and confirm that settlements with the IESO are performed as shown in this guidance. Please note that embedded generation guidance in this document is not new, but all components of the previously issued guidance for embedded generation have been consolidated in this document.

Responses:

a) The question was asked and answered as part of CPUCs response to the notice of incomplete application. Please see response to question 7 where CPUC clarified. For ease of reference, CPUC does not have any Fit/MicroFit.

b) N/A.

9-Staff-89

Ref: Account 1595 (2012), 1595 Analysis Workform

Preamble:

CPUC is requesting to recover a residual debit balance of $179,009 in its Account 1595 (2012) per Table 1, which is close to the 2.1.7 filing as of December 31, 2017. OEB staff believes that the balance in 2.1.7 for 1595 (2012) may be incorrect, as it may not be correctly reflecting the total disposition in 2012 of a credit amount or $279,456.

The proposed amount is not consistent with the 1595 Analysis Workform for 2012, which shows a residual balance of a credit of $402. OEB staff reviewed the 1595 Analysis Workform, which correctly shows the balances that were approved for both, principal and interest. OEB staff is of the view that the 1595 Analysis Workform (2012) is correctly reflecting the residual balance of credit of $402.

OEB staff notes that CPUC had total dispositions for a credit amount of $279,456 in 2012. This amount included a credit disposition for Account 1562 of $178,246, which is very close to the amount being requested for disposition. As per the 1595 Analysis Workform, the rate riders were refunded to customers for all, except for a credit of $402 residual amount. It is likely that this amount was never recorded in Account 1595 (2012) on disposition, thereby resulting in the rate riders creating a debit balance in the account.

Questions:

a) Please provide evidence that Account 1562 disposition in 2012 was correctly recorded as a credit in Account 1595 (2012) on disposition.

b) Please provide an explanation for the discrepancy between the 1595 Analysis Workform and the amount requested for disposition.

Responses: This came from Tiffany.

Upon review during the 2018 audit, it was noted that the 2012 regulatory accounts will be written off, with a corresponding adjustment through the opening deficit as of January 1, 2017. When reviewing the details relating to the 2012 regulatory accounts, it was noted that throughout the 2012 – 2016 the impact on the rate rider for the 2012 regulatory balances was cancelled out by a separate journal entry which created the accounts with 1595. As a result, it was determined that the opening balance as of January 1, 2017 will be adjusted. Within the 2018 financial statements this was determined this was an immaterial adjustment (as it related to only 4% of total assets). This adjustment will be reflected within the 2018 financial statements and once approved by the Board of Directors the adjustment and related note disclosure will be provided to the OEB as part of the filing requirements.

9-Staff-98

Ref: LRAMVA Workform, Tab 6 (carrying charges)
DVA Continuity Schedule, Tab 2b, August 31, 2018

Preamble:

It appears that projected interest on the LRAMVA was calculated to September 30, 2018.

Questions:

a) Please update Table 6 with the most recently approved OEB prescribed interest to calculate carrying charges projected to April 30, 2019.

b) Please confirm the LRAMVA principal balance and projected carrying charges, which are requested for disposition in this application.

c) Please revise Tab 2b of the DVA continuity schedule accordingly to reflect the appropriate projected interest amounts to April 30, 2019 for Account 1568.

Responses:

a) Tab 6 was updated with the following interest rates

2018 Q4	2.17%
2019 Q1	2.45%
2019 Q2	2.45%

b) Please see CPUCs revised balances below. CPUC has updated the allocation of a Retrofit program in 2016 which was originally allocated to the Streetlighting class to the GS<50. The actual Retrofit program for the Streetlighting class occurred in 2017.

Description	Residential	GS<50 kW	GS 50kW to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	kWh	kWh	kw	kWh	kw	kw	
2011 Actuals	$300.12	$1,121.41	$0.00	$0.00	$0.00	$0.00	$1,421.53
2011 Forecast	($9,285.50)	($107.41)	($526.49)	$0.00	$0.00	$0.00	($9,919.40)
Amount Cleared							
2012 Actuals	$576.76	$5,586.02	$2,359.29	$0.00	$0.00	$0.00	$8,522.07
2012 Forecast	($12,289.63)	($153.19)	($735.38)	$0.00	$0.00	$0.00	($13,178.20)
Amount Cleared							
2013 Actuals	$973.66	$6,681.47	$2,396.78	$0.00	$0.00	$0.00	$10,051.90
2013 Forecast	($12,380.66)	($154.07)	($727.32)	$0.00	$0.00	$0.00	($13,262.06)
Amount Cleared							
2014 Actuals	$1,745.93	$6,498.15	$3,855.99	$0.00	$0.00	$0.00	$12,100.07
2014 Forecast	($12,562.73)	($155.83)	($724.68)	$0.00	$0.00	$0.00	($13,443.24)
Amount Cleared							
2015 Actuals	$2,422.70	$9,861.63	$3,583.84	$0.00	$0.00	$0.00	$15,868.17
2015 Forecast	($12,744.80)	($157.59)	($730.94)	$0.00	$0.00	$0.00	($13,633.33)
Amount Cleared							

2016 Actuals	$4,252.80	$8,706.20	$2,684.63	$0.00	$0.00	$0.00	$15,643.63
2016 Forecast	($12,744.80)	($157.59)	($730.94)	$0.00	$0.00	$0.00	($13,633.33)
Amount Cleared							
2017 Actuals	$7,812.80	$6,023.55	$2,653.51	$0.00	$0.00	$0.00	$16,489.86
2017 Forecast	($12,744.80)	($157.59)	($730.94)	$0.00	$0.00	$0.00	($13,633.33)
Amount Cleared							
Carrying Charges	($5,218.85)	$2,899.24	$809.48	$0.00	$0.00	$0.00	($1,510.13)
Total LRAMVA Balance	**-$71,887**	**$46,334**	**$13,437**	**$0**	**$0**	**$0**	**-$12,116**
Note: LDC to make note of assumptions included above, if any							
	-$66,668.17	$43,435.15	$12,627.36			$0.00	**-$10,606**

c) The model was revised accordingly

9-Staff-99

Ref: Exhibit 9, Section 9.9.2, page 44 and 48
Report of the OEB, Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR), July 31, 2009[31]
DVA Continuity Schedule, Tabs 2b, 4, 5 and 7, August 31, 2018

Preamble:

The EDDVAR Report states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year, but a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate. The EDDVAR Report further notes that the balances in Group 1 accounts are allocated on a kWh basis, while the allocation of Group 2 accounts is generally determined on a case-by-case basis.

The rate rider for the LRAMVA credit balance is proposed to be disposed over the next four years (or 48 months). It is noted that the specific recovery period was chosen in an effort to mitigate rates.

Questions:

a) Please explain why the LRAMVA balance for the residential class is proposed to be allocated by number of customers, rather than by kWh. If a revision is required, please update the allocation factor for the residential class in Tab 7 of the DVA continuity schedule in order to reflect the correct allocator for determining the LRAMVA rate rider for the residential class.

b) If the LRAMVA balance for the residential class were to be allocated on the basis of kWh, please clarify whether CPUC is still seeking to dispose of Account 1568 over a period of 48 months.

    a. If yes, please discuss the rationale and potential rate impacts that are mitigated as compared to a shorter disposition timeframe.

    b. If not, please confirm the proposed allocation method for the residential LRAMVA and the period of disposition for Account 1568.

c) Please explain the discrepancy in the LRAMVA amounts shown in the DVA continuity schedule of a credit balance of $17,719 (in tabs 2b and tab 5) and a credit balance of $7,880 (tabs 4 and 7). Please confirm whether Chapleau would agree to remove any previously disposed amounts in the DVA continuity

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[31] EB-2008-0046

schedule to ensure that the LRAMVA amounts requested for disposition are consistent. Please update the evidence where required.

d) Please refile the revised rate riders associated with the LRAMVA balance, as applicable, based on CPUC's responses above.

Responses:

a) The continuity schedule lists 1568 under the heading of Group 2. As per the Board's letter issued July 16, 2015 outlining details regarding the transition to fully fixed DSC for the residential class, residential rates for Group 2 are to be on a per customer basis.

b) In revising the allocation of a Retrofit program from Street Lights to GS<50kWh, the balance is now in a credit position. If the balance is approved as such, the utility will be seeking a disposition of 1 year.

c) CPUC agrees to remove previous disposition to ensure that LRAMVA amounts are consistent.

d) A revised model has been filed along with these responses.

9-Staff-100

Ref: LRAMVA Workform, August 31, 2018
DVA Continuity Schedule, Tab 7, August 31, 2018
Bill Impact and Tariff model, January 10, 2019

Questions:

a) If CPUC made any changes to the LRAMVA work form as a result of its responses to these LRAMVA interrogatories, please file an updated LRAMVA work form.

b) Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".

c) Please update and refile changes to the DVA continuity schedule, bill impacts model, and associated tariff as applicable.

d) Please confirm that updates have been made to the revised DVA continuity schedule accompanying these interrogatories.

Responses:

a) This IR was asked and answered at 9-Staff-99 d)

b) CPUC agrees to update tab 2 a if any changes to the mechanics of the work form has been done.

c) CPUC has updated the DVA continuity schedule to reflect the newly calculated LRAMVA. Bill impacts and other affected models have also been filed along with these responses.

d) Ask and answered in c)

9.0 –VECC -44

Reference: Exhibit 9, pg. 38 of 53

a) Why does account 1576 attract no carrying charges?
b) Why was a 2 year disposition period chosen to return the $870,367 to CPUC's customers (instead of say 1 year)?

Responses:

a) The model doesn't seem to allow carrying charges for balances in 1576

b) Page 38 of Ex 9 should have quoted $30,876. CPUC is open to disposing it over a period of 1 year rather than 2.