CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

EXHIBIT 7:
COST ALLOCATION

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7.1 COST ALLOCATION STUDY

7.1.1 OVERVIEW OF COST ALLOCATION

CNPI has prepared and is filing a cost allocation study consistent with its understanding of the Directions and Policies in the Board's Reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports") and all subsequent updates.

CNPI used Version 1.0 of the OEB's 2021 Cost Allocation Model, issued May 14, 2020. Inputs to the model reflect CNPI's 2022 Test Year revenue requirement, CNPI's 2022 load forecast, and other requirements outlined in the Cost Allocation Reports. CNPI scaled its class load profiles from its previous cost of service applications, for the reasons discussed in Section 7.1.3 below.

Consistent with CNPI's 2017 cost of service application, the cost allocation study was completed on a harmonized basis for CNPI's Fort Erie, Eastern Ontario Power, and Port Colborne service areas, following distribution rate harmonization in 2016. CNPI's 2017 OEB-approved revenue-to-cost ratios ("R/C ratios") are summarized in the following table:

Table 7 - 1: 2017 OEB-Approved Revenue-to-Cost Ratios

Customer Class	2017 Approved R/C Ratio
Residential	95%
GS < 50	109%
GS 50 to 4,999 kW	108%
Embedded Distributor	100%
Street Light	120%
Sentinel Light	104%
USL	95%

No adjustments to CNPI's revenue-to-cost ratios were required during the 2018-2021 Incentive Rate Mechanism (IRM) years, since the 2017 OEB-approved R/C ratios were all within the OEB's policy ranges.

Section 7.2 of this Exhibit provides the results of CNPI's 2022 cost allocation study. Status quo R/C ratios continue to remain within the OEB's policy ranges for all classes except Street Lighting, where a reallocation of costs is required to bring the class revenue down to the 120% upper limit.

7.1.2 COST ALLOCATION MODEL – SUMMARY OF INPUTS

CNPI populated the information in Sheet I3, Trial Balance Data with the 2022 forecasted trial balance amounts that are consistent with Exhibits 2 through 6. Entries for target net income, PILs, interest on long term debt, and 2022 Test Year proposed revenue requirement and rate base are all consistent with the Revenue Requirement Work Form (RRWF) cells referenced in Sheet I3.

In Sheet I4, Break-out of Assets, CNPI updated contribution, depreciation and amortization expense values based on 2022 forecasted values. Rate base amounts associated with poles, overhead conductors and devices, and underground conductors and devices, were broken out into primary and secondary costs only, consistent with CNPI's 2017 cost allocation study.

In Sheet I5.1, Miscellaneous Data, CNPI entered 2022 Test Year values for the deemed equity component of rate base and working capital allowance consistent with values presented throughout the current Application. Values for structure km and the proportion of pole rental revenue from secondary poles are consistent with CNPI's 2017 cost allocation study, adjusted for a marginal increase in structure km since 2017.

CNPI confirms that it used LDC-specific weighting factors in Sheet I5.2, Weighting Factors, instead of continuing to use the OEB's previous default factors. Further discussion of these weighting factors is provided in Section 7.1.4 below.

Sheet I6.1 contains updated load forecast details by rate class, consistent with CNPI's 2022 Test Year load forecast, as presented in Exhibit 3 of the Application. The existing rates entered in this sheet reflect the rates approved in CNPI's 2021 IRM application.

Sheet I6.2 has been updated with the required Bad Debt and Late Payment revenue data for historical years, as well as the number of customers (and connections, where applicable), consistent with CNPI's 2022 Test Year load forecast, as presented in Exhibit 3.

CNPI updated the capital cost per meter information in Sheet I7.1 and the meter reading information in Sheet I7.2 to reflect its completed deployment of smart meters and MIST meters, with consideration of additional metering activity in recent years.

The demand data entered in Sheet I8, Demand Data, reflects the continued use of the load profiles previously provided by Hydro One, scaled for consistency with CNPI's 2022 load forecast. The calculation of the scaling factor, and the rationale for continued use of the Hydro One load profiles in provided in Section 7.1.3 below.

A live Excel version of OEB's Cost Allocation Model has been filed along with this Application. CNPI confirms that it has also populated sheets 11 and 12 of the OEB's Revenue Requirement Work Form consistent with the output of the cost allocation model.

7.1.3 LOAD PROFILES

Section 2.7.1 of the Filing Requirements indicates that distributors should make best efforts to update all classes' load profiles using the most recent available data. In recent years, CNPI was an active participant in a Demand Profile Working Group coordinated by Utilities Standards Forum (USF). The USF working group ultimately developed a cost-effective methodology for weather-normalizing interval data for the purpose of updating load profiles. The USF Demand Profile Methodology was ultimately advanced by Wellington North Power in EB-2020-0061.

In preparing this Application, CNPI determined that it had suitable interval data for all rate classes available for the period beginning September 26, 2018. CNPI determined that smart meter data interval data prior to this date was archived in a format that made it cost-prohibitive to extract and compile the data in a workable format.

CNPI believes that an important concept within the USF Demand Profile Methodology is that the weather-normalized non-coincident peak (NCP) and coincident peak (CP) results for more than one year are averaged for the purpose of determining updated NCP and CP inputs to the OEB's Cost Allocation model. As a result of the data limitations discussed above, CNPI did not have a complete data set for 2018, leaving 2019 and 2020 as the two years to which the USF Demand Profile Methodology could be applied. Due to the material shift in load between rate classes resulting from the COVID-19 pandemic (see Exhibit 3), CNPI does not consider 2020 interval data to be representative of past or future load profiles. As a result of these circumstances, CNPI was unable to use the USF Demand Profile Methodology.

In an attempt to overcome the limitations discussed above, CNPI attempted to develop a regression analysis of class-specific interval data, with hourly weather data as the independent variables. CNPI started this analysis with residential rate class, using hourly weather information available at the Pearson Airport in Toronto. CNPI observed poor statistical results on an hourly basis, both before and after attempting to introduce other variables similar to those included in its load forecast.

CNPI intends to extract and archive smart meter data in a format that facilitates analysis for future cost allocation studies and therefore expects to have a complete data set spanning the 2019-2025 period at the time of filing its next cost of service application in 2026. In order to update its demand inputs for the 2022 Test Year, CNPI used the values from its previous cost allocation study, with values for each customer class scaled by the ratio of 2022 to 2017 load forecasts as illustrated in Table 7 - 2 below.

Table 7 - 2: CP and NCP Scaling Factors

	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Light	Sentinel Light	USL	Embedded Distributor
2017 Approved kWh	201,294,289	69,390,323	190,144,345	2,991,556	629,014	1,462,761	5,205,754
2022 Test Year kWh	207,937,091	66,588,571	176,291,005	1,449,102	514,043	1,340,169	5,185,553
Scaling Factor	1.03	0.96	0.93	0.48	0.82	0.92	1.00

7.1.4 WEIGHTING FACTORS

As part of its 2013 and 2017 cost allocation studies, CNPI developed and reviewed weighting factors based on input from staff with knowledge of each particular cost element. These weighting factors and supporting rationale were further reviewed during the preparation of the 2022 cost allocation study and updated where required. The weighting factors summarized below are input in Sheet I5.2 of the OEB cost allocation model.

WEIGHTING FACTOR FOR SERVICES ACCOUNT 1855

The weighting factors are consistent with the values used in CNPI's previous cost allocation studies, which were based on analysis of the relative material costs and labour effort required to connect a new service for a typical customer within each rate class. When the Embedded Distributor customer class was established in CNPI's 2017 cost of service application, it was assigned the same weighting factors throughout the cost allocation as the General Service 50 to 4,999 class. In the current application CNPI zeroed out the Account 1855 weighting factor for the Embedded Distributor class to reflect that this is a primary metered account and none of the components at the demarcation point would be included in Account 1855.

WEIGHTING FACTORS FOR BILLING AND COLLECTING

Weighting factors for billing and collecting were previously derived through input from customer service supervisors related to the relative billing complexity between various rate classes. For its 2022 cost allocation study, CNPI undertook additional analysis of the costs recorded in Accounts 5315, 5320 and 5340 are and determined that in addition to billing complexity, cost drivers should also include the following:

- Number of meters
- Number of bills (without regard to billing complexity)
- Bad debt

For each cost driver, Table 7 - 3 below summarizes the allocation factor applicable to each customer class, using an average of 2017-2020 actual data.

Table 7 - 3: Billing and Collecting – Allocation Factors by Cost Driver

	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Light	Sentinel Light	USL	Embedded Distributor	Total
Average # of Accounts								
2017-2020 Average	26,564	2,502	195	14	36	48	1	**29,360**
% Allocator	90.5%	8.5%	0.7%	0.0%	0.1%	0.2%	0.0%	**100%**
# of Retail Meters								
2017-2020 Average	26,564	2,502	195	0	0	0	1	**29,261**
% Allocator	90.8%	8.5%	0.7%	0.0%	0.0%	0.0%	0.0%	**100%**
# of Bills								
2017-2020 Average	318,768	30,020	2,338	173	436	572	12	**352,317**
% Allocator	90.5%	8.5%	0.7%	0.0%	0.1%	0.2%	0.0%	**100%**
Weighting Factor (2017)	1.00	1.00	5.00	1.80	0.90	1.25	5.00	
Bill Complexity (# of Bills x 2017 Weighting)								
2017-2020 Average	318,768	30,020	11,688	311	392	714	60	**361,953**
% Allocator	88.1%	8.3%	3.2%	0.1%	0.1%	0.2%	0.0%	**100%**
Bad Debt								
2017-2020 Average	$164,788	$8,815	$2,290	$0	$0	$0	$0	**175,892**
% Allocator	93.7%	5.0%	1.3%	0.0%	0.0%	0.0%	0.0%	**100%**

Table 7 - 4 summarizes the calculation of the 2022 cost allocation weighting factors that result from applying the various cost driver factors to the costs in Accounts 5315, 5320 and 5340.

Table 7 - 4: Billing and Collecting – Determination of Weighting Factors

	2017-2020 Avg	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Light	Sentinel Light	USL	Embedded Distributor	Total
Rate Class Allocations by Cost Driver									
# of Meters	$42,797	$38,852	$3,659	$285	$0	$0	$0	$1	$42,797
# of Bills	$388,272	$351,299	$33,084	$2,576	$190	$480	$630	$13	$388,272
Bill Complexity	$509,215	$448,460	$42,234	$16,443	$437	$552	$1,005	$84	$509,215
Bad Debt	$273,197	$255,950	$13,691	$3,556					$273,197
Total	**$1,213,481**	**$1,094,560**	**$92,667**	**$22,860**	**$627**	**$1,033**	**$1,635**	**$99**	**$1,213,481**
Calculate Billing and Collecting Factors									
Avg Annual Acct 5315, 5320, 5340 Costs		$1,094,560	$92,667	$22,860	$627	$1,033	$1,635	$99	$1,213,481
Avg Annual # of Bills		318,768	30,020	2,338	173	436	572	12	352,317
Average Annual Cost/Bill		$3.43	$3.09	$9.78	$3.63	$2.37	$2.86	$8.26	$3.44
Weighting Factor (Residential = 1.0)		**1.00**	**0.90**	**2.85**	**1.06**	**0.69**	**0.83**	**2.41**	

7.1.5 SELECTED INPUT AND OUTPUT SHEETS

In accordance with the Filing Requirements, distributors using the OEB-issued model must file a hard copy of input sheets I6 and I8, and output sheets O1 and O2 (first page only). The required information is included as Appendix 7-A to this Exhibit.

Sections 7.2.1 and 7.2.2 below provide an analysis and summary of the results from the 2020 cost allocation study contained in output sheets O1 and O2.

7.1.6 SPECIFIC CUSTOMER CLASSES

Information in this section addresses OEB policy guidance on cost allocation matters for specific customer classes, as outlined in Section 2.7.1.1 of the Filing Requirements.

EMBEDDED DISTRIBUTOR CLASS

CNPI supplies Hydro One Networks Inc. ("HONI") as an embedded distributor within its Port Colborne service area, using distribution assets that also serve other CNPI customers (i.e. these assets are not dedicated to supplying HONI as an embedded distributor). In CNPI's 2017 cost of service application (EB-2016-0061), HONI requested that CNPI establish a separate embedded distributor rate, and CNPI proceeded with its 2017 cost allocation study and rate design on that basis. CNPI has billed HONI as an embedded distributor since 2017 and proposes to continue to maintain a distinct Embedded Distributor class for cost allocation and rate design purposes in this Application.

CNPI informed HONI of its intent to use cost allocation and rate design methodologies consistent with its 2017 cost of service application, subject to revisions to Embedded Distributor weighting factors as discussed above. CNPI also informed HONI of the results of its cost allocation study and rate design process prior to filing the Application.

UNMETERED LOADS (INCLUDING STREET LIGHTING)

CNPI acknowledges the OEB's 2015 change in cost allocation policy for the Street Lighting rate class, and confirms that the "street lighting adjustment factor" has been appropriately calculated by the OEB cost allocation model. CNPI implemented the required changes to cost allocation for its street lighting rate class in its 2017 cost allocation study, which was discussed with customers at that time. The 2022 cost allocation methodology is unchanged from the 2017 methodology.

The decrease in costs allocated to the Street Lighting customer class in 2022 results from lower demand determinants following conversions to LED lighting. As a result of the decreased cost allocation, R/C ratios were rebalanced to bring the Street Lighting class back to the OEB policy range, resulting in decreased rates.

MICROFIT

CNPI applies the OEB's generic rate of $4.35 per month. In accordance with the Filing Requirements CNPI has not included microFIT as a separate class in the cost allocation model.

STANDBY RATES

Standby customers are not a distinct customer class within CNPI's cost allocation study since these customers are billed as General Service 50 to 4,999 kW customers, with the standby rate applying to contracted capacity that is not utilized in a given month. CNPI has determined that a full review of its standby charge methodology would be preferable to requesting that its existing standby charge be made final, as further detailed in Exhibit 8.

NEW OR ELIMINATED CUSTOMER CLASSES

CNPI is not proposing to add any new customer classes or eliminate any existing customer classes in this Application.

7.2 COST ALLOCATION RESULTS AND ANALYSIS

7.2.1 CLASS REVENUE REQUIREMENTS

Table 7 - 5 summarizes CNPI's allocated costs by rate class, based on the results of CNPI's 2022 Test Year cost allocation study. The output from the OEB's Cost Allocation Model presented below are consistent with values populated in Table A (column "7A") and Table B (column "7E") on Sheet 11 of the RRWF.

Table 7 - 5: Allocated Costs by Rate Class

Customer Class	Service RR	Misc Rev	Base RR
Residential	15,195,555	928,059	14,267,495
GS < 50	2,832,293	142,905	2,689,388
GS 50 to 4,999 kW	4,842,632	235,421	4,607,211
Embedded Distributor	153,933	8,690	145,243
Street Light	297,981	17,960	280,021
Sentinel Light	59,412	3,841	55,571
USL	77,155	4,375	72,780
Total	**23,458,959**	**1,341,251**	**22,117,708**

Table 7 - 6, summarizes CNPI's calculated 2022 distribution revenue by rate class, under four scenarios: (a) existing rates applied to CNPI's 2022 Test Year load forecast; (b) the base revenue requirement allocation resulting from the 2022 Cost Allocation Model; (c) prorating existing rates applied to CNPI's 2022 Test Year load forecast to yield the Test Year base revenue requirement (the "Status Quo" scenario); and (d) CNPI's proposed class revenues for the 2022 Test Year following the revenue-to-cost ratio adjustments discussed in Section 7.2.3.

Table 7 - 6: Distribution Revenue (Base Revenue Requirement) Allocation by Rate Class

Customer Class	Current Rates		OEB CA Model Results		Status-Quo Rates		Proposed Rates	
	$	%	$	%	$	%	$	%
Residential	12,219,333	62.47%	14,267,495	64.51%	13,817,788	62.47%	13,859,017	62.66%
GS < 50	2,664,429	13.62%	2,689,388	12.16%	3,012,973	13.62%	3,012,973	13.62%
GS 50 to 4,999 kW	4,094,805	20.94%	4,607,211	20.83%	4,630,462	20.94%	4,630,462	20.94%
Embedded Distributor	126,194	0.65%	145,243	0.66%	142,702	0.65%	142,702	0.65%
Street Light	336,789	1.72%	280,021	1.27%	380,846	1.72%	339,617	1.54%
Sentinel Light	52,357	0.27%	55,571	0.25%	59,206	0.27%	59,206	0.27%
USL	65,202	0.33%	72,780	0.33%	73,732	0.33%	73,732	0.33%
Total	**19,559,110**	**100%**	**22,117,708**	**100%**	**22,117,708**	**100%**	**22,117,708**	**100%**

7.2.2 REVENUE-TO-COST RATIOS

Table 7 - 7, which is reproduced from Table 7C on Sheet 11 of the RRWF, compares CNPI's 2017 approved R/C ratios to two scenarios: (a) R/C ratios resulting from the class revenue associated with Status Quo scenario outlined in the previous section; and (b) CNPI's proposed R/C ratios for the 2022 Test Year adjusted to ensure all rate classes fall within the OEB's policy ranges as discussed in Section 7.2.3.

Table 7 - 7: Revenue-to-Cost Ratio Summary

Customer Class	2017 Approved	Status Quo	Proposed	Policy Range
Residential	95.06%	97.04%	97.31%	85 - 115
GS < 50	109.35%	111.42%	111.42%	80 - 120
GS 50 to 4,999 kW	107.60%	100.48%	100.48%	80 - 120
Embedded Distributor	100.00%	98.35%	98.35%	80 - 120
Street Light	120.00%	133.84%	120.00%	80 - 120
Sentinel Light	103.78%	106.12%	106.12%	80 - 120
USL	95.05%	101.23%	101.23%	80 - 120

7.2.3 REBALANCING REVENUE-TO-COST RATIOS

The Status Quo revenue-to-cost ratio of 133.84% for the Street Lighting rate class is above the OEB's policy range of 80-120%. The status quo R/C ratios for all other rate classes are within the OEB's applicable policy ranges.

CNPI therefore proposes to rebalance its R/C ratios for the 2022 Test Year such that the ratio for the Street Lighting class is reduced to the upper limit of the OEB's policy range (i.e. 120%). In order to achieve this rebalancing, CNPI has reduced the amount of revenue requirement allocated to the Street Lighting customer class by $41,229 as compared to the amount that would be recovered through the use of Status Quo rates. In order to maintain revenue neutrality, an equivalent amount is added to the allocation to the Residential customer class, since this class has the lowest R/C ratio out of any other class. The proposed reallocation is shown in the following table:

Table 7 - 8: Revenue Reallocation to Achieve Proposed Revenue-to-Cost Ratios

Customer Class	$ Reallocation
Residential	41,229
Street Light	(41,229)
Total	**0**

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APPENDIX 7-A:
COST ALLOCATION MODEL
(SELECTED SHEETS)

Ontario Energy Board

2021 Cost Allocation Model

EB-2021-0011

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	459,305,534
Total kWs from Load Forecast	542,083
Deficiency/sufficiency (RRWF 8. cell F51)	- 2,558,598
Miscellaneous Revenue (RRWF 5. cell F48)	1,341,251

			1	2	3	7	8	9	10
	ID	**Total**	**Residential**	**GS <50**	**GS 50 to 4,999 kW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Billing Data									
Forecast kWh	**CEN**	459,305,534	207,937,091	66,588,571	176,291,005	1,449,102	514,043	1,340,169	5,185,553
Forecast kW	**CDEM**	542,083	-	-	522,202	4,403	1,615	-	13,863
Forecast kW, included in CDEM, of customers receiving line transformer allowance		296,494	-	-	296,494	-	-	-	-
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	459,305,534	207,937,091	66,588,571	176,291,005	1,449,102	514,043	1,340,169	5,185,553
Existing Monthly Charge			$37.40	$31.58	$169.70	$4.09	$5.70	$49.79	$610.63
Existing Distribution kWh Rate			$0.0000	$0.0257				$0.0271	
Existing Distribution kW Rate					$7.4535	$8.8982	$6.5951		$8.5743

Existing TOA Rate					$0.60				
Additional Charges								($88,222.18)	
Distribution Revenue from Rates		$19,737,007	$12,219,333	$2,664,429	$4,272,702	$336,789	$52,357	$65,202	$126,194
Transformer Ownership Allowance		$177,896	$0	$0	$177,896	$0	$0	$0	$0
Net Class Revenue	**CREV**	$19,559,110	$12,219,333	$2,664,429	$4,094,805	$336,789	$52,357	$65,202	$126,194

Ontario Energy Board

2021 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet -

			1	2	3	7	8	9	10
	ID	Total	Residential	GS <50	GS 50 to 4,999 kW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$162,317	$153,185	$8,393	$740	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$160,566	$122,546	$13,279	$24,568	$48	$21	$105	$0
Number of Bills	CNB	360,323	326,720	30,180.58	2,242.03	168.00	420.00	580.11	12.00
Number of Devices	CDEV					6,064	610	196	
Number of Connections (Unmetered)	CCON	4,442				3,972	274	196	
Total Number of Customers	CCA	30,027	27,227	2,515	187	14	35	48	1
Bulk Customer Base	CCB	30,027	27,227	2,515	187	14	35	48	1
Primary Customer Base	CCP	30,246	27,227	2,515	187	233	35	48	1
Line Transformer Customer Base	CCLT	30,200	27,227	2,515	142	233	35	48	-
Secondary Customer Base	CCS	29,512	26,778	2,515	122	14	35	48	-
Weighted - Services	CWCS	32,792	26,778	3,521	536	1,589	192	176	-
Weighted Meter -Capital	CWMC	7,881,216	5,230,791	1,548,182	1,080,128	-	-	-	22,116
Weighted Meter Reading	CWMR	29,930	27,227	2,515	187	-	-	-	1
Weighted Bills	CWNB	361,251	326,720	27,163	6,390	178	290	481	29

Bad Debt Data

Historic Year:	2017	304,034	290,345	11,469	2,219				
Historic Year:	2018	110,739	101,760	8,979	-				
Historic Year:	2019	72,179	67,448	4,730	-				
Three-year average		**162,317**	**153,185**	**8,393**	**740**	**-**	**-**	**-**	**-**

Ontario Energy Board

2021 Cost Allocation Model

EB-2021-0011

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS 50 to 4,999 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
		CP Sanity Check	Check 4 CP	Pass	Pass	Check 4CP and 12CP	Check 12CP	Check 4CP and 12CP	Pass
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	78,072	36,857	9,931	30,048	-	57	56	1,123
Bulk Delivery CP	BCP1	78,072	36,857	9,931	30,048	-	57	56	1,123
Total Sytem CP	DCP1	78,072	36,857	9,931	30,048	-	57	56	1,123
4 CP									
Transformation CP	TCP4	308,928	159,462	36,761	108,197	277	224	368	3,639
Bulk Delivery CP	BCP4	308,928	159,462	36,761	108,197	277	224	368	3,639
Total Sytem CP	DCP4	308,928	159,462	36,761	108,197	277	224	368	3,639
12 CP									
Transformation CP	TCP12	850,767	420,487	107,117	310,528	1,476	702	1,546	8,912
Bulk Delivery CP	BCP12	850,767	420,487	107,117	310,528	1,476	702	1,546	8,912
Total Sytem CP	DCP12	850,767	420,487	107,117	310,528	1,476	702	1,546	8,912
NON CO_INCIDENT PEAK									
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP									
Classification NCP from Load Data Provider	DNCP1	90,254	44,876	12,125	31,015	370	66	284	1,518
Primary NCP	PNCP1	90,109	44,876	12,125	30,870	370	66	284	1,518
Line Transformer NCP	LTNCP1	83,992	44,876	12,125	26,271	370	66	284	-
Secondary NCP	SNCP1	83,992	44,876	12,125	26,271	370	66	284	-
4 NCP									
Classification NCP from Load Data Provider	DNCP4	346,866	172,576	44,951	120,901	1,477	262	1,131	5,569
Primary NCP	PNCP4	346,305	172,576	44,951	120,340	1,477	262	1,131	5,569
Line Transformer NCP	LTNCP4	322,849	172,576	44,951	102,453	1,477	262	1,131	-
Secondary NCP	SNCP4	322,849	172,576	44,951	102,453	1,477	262	1,131	-
12 NCP									
Classification NCP from Load Data Provider	DNCP12	954,975	458,437	124,916	349,757	4,428	746	3,306	13,385
Primary NCP	PNCP12	953,299	458,437	124,916	348,080	4,428	746	3,306	13,385
Line Transformer NCP	LTNCP12	886,969	458,437	124,916	295,136	4,428	746	3,306	-
Secondary NCP	SNCP12	886,969	458,437	124,916	295,136	4,428	746	3,306	-

Ontario Energy Board

2021 Cost Allocation Model

EB-2021-0011

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS 50 to 4,999 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
crev	Distribution Revenue at Existing Rates	$19,559,110	$12,219,333	$2,664,429	$4,094,805	$336,789	$52,357	$65,202	$126,194
mi	Miscellaneous Revenue (mi)	$1,341,251	$928,059	$142,905	$235,421	$17,960	$3,841	$4,375	$8,690
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$20,900,361	$13,147,392	$2,807,334	$4,330,226	$354,750	$56,198	$69,577	$134,884
	Factor required to recover deficiency (1 + D)	1.1308							
	Distribution Revenue at Status Quo Rates	$22,117,708	$13,817,788	$3,012,973	$4,630,462	$380,846	$59,206	$73,732	$142,702
	Miscellaneous Revenue (mi)	$1,341,251	$928,059	$142,905	$235,421	$17,960	$3,841	$4,375	$8,690
	Total Revenue at Status Quo Rates	$23,458,959	$14,745,847	$3,155,878	$4,865,883	$398,806	$63,047	$78,106	$151,392
	Expenses								
di	Distribution Costs (di)	$3,296,015	$2,032,735	$389,506	$766,273	$58,602	$10,949	$13,362	$24,586
cu	Customer Related Costs (cu)	$2,604,973	$2,162,781	$293,996	$141,770	$746	$1,213	$2,016	$2,451
ad	General and Administration (ad)	$4,162,141	$2,934,673	$483,436	$661,257	$42,988	$8,778	$11,133	$19,877
dep	Depreciation and Amortization (dep)	$5,625,717	$3,425,326	$715,714	$1,325,793	$80,394	$15,806	$20,492	$42,192
INPUT	PILs (INPUT)	$430,483	$257,069	$52,612	$107,898	$6,385	$1,256	$1,670	$3,592
INT	Interest	$2,951,625	$1,762,607	$360,739	$739,810	$43,780	$8,610	$11,454	$24,625
	Total Expenses	$19,070,954	$12,575,191	$2,296,004	$3,742,800	$232,895	$46,612	$60,128	$117,324
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$4,388,005	$2,620,363	$536,289	$1,099,831	$65,085	$12,800	$17,027	$36,609
	Revenue Requirement (includes NI)	$23,458,959	$15,195,555	$2,832,293	$4,842,632	$297,981	$59,412	$77,155	$153,933
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$193,458,897	$117,363,139	$23,774,013	$46,522,429	$2,964,372	$581,106	$748,348	$1,505,489
gp	General Plant - Gross	$35,798,037	$21,547,528	$4,354,287	$8,802,166	$554,393	$107,643	$140,501	$291,518
accum dep	Accumulated Depreciation	($80,406,898)	($49,170,451)	($10,044,667)	($18,868,279)	($1,191,744)	($238,233)	($303,070)	($590,453)
co	Capital Contribution	($21,950,842)	($13,912,182)	($2,580,302)	($4,698,023)	($438,138)	($79,428)	($92,905)	($149,863)
	Total Net Plant	$126,899,193	$75,828,033	$15,503,330	$31,758,293	$1,888,884	$371,087	$492,875	$1,056,691
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$0	$0	$0	$0	$0	$0	$0	$0
	OM&A Expenses	$10,063,129	$7,130,189	$1,166,939	$1,569,299	$102,336	$20,940	$26,511	$46,915
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$10,063,129***	***$7,130,189***	***$1,166,939***	***$1,569,299***	***$102,336***	***$20,940***	***$26,511***	***$46,915***
	Working Capital	$754,735	$534,764	$87,520	$117,697	$7,675	$1,570	$1,988	$3,519
	Total Rate Base	$127,653,928	$76,362,797	$15,590,851	$31,875,990	$1,896,559	$372,658	$494,863	$1,060,210
		Rate Base Input equals Output							
	Equity Component of Rate Base	$51,061,571	$30,545,119	$6,236,340	$12,750,396	$758,624	$149,063	$197,945	$424,084
	Net Income on Allocated Assets	$4,388,005	$2,170,656	$859,874	$1,123,082	$165,911	$16,436	$17,979	$34,068
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$4,388,005	$2,170,656	$859,874	$1,123,082	$165,911	$16,436	$17,979	$34,068
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	97.04%	111.42%	100.48%	133.84%	106.12%	101.23%	98.35%

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Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
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Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets	Total	1 Residential	2 GS <50	3 GS 50 to 4,999 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
EXISTING REVENUE MINUS ALLOCATED COSTS	**($2,558,598)**	($2,048,162)	($24,959)	($512,405)	$56,769	($3,214)	($7,578)	($19,049)
Deficiency Input equals Output								
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	($449,707)	$323,585	$23,251	$100,825	$3,635	$951	($2,541)
RETURN ON EQUITY COMPONENT OF RATE BASE	8.59%	7.11%	13.79%	8.81%	21.87%	11.03%	9.08%	8.03%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9	10
	Residential	GS <50	GS 50 to 4,999 kW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Customer Unit Cost per month - Avoided Cost	$5.07	$11.38	$85.63	$0.00	$0.16	$0.36	$338.38
Customer Unit Cost per month - Directly Related	$8.07	$17.10	$130.19	$0.01	$0.29	$0.67	$496.37
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$27.01	$37.44	$162.89	$5.37	$17.81	$15.84	$361.84
Existing Approved Fixed Charge	$37.40	$31.58	$169.70	$4.09	$5.70	$49.79	$610.63