Exhibit 7:

COST ALLOCATION

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Exhibit 7: Cost Allocation

Tab 1 (of 2): Cost Allocation Study

OVERVIEW OF COST ALLOCATION

1. OVERVIEW

NOW Inc. retained Elenchus to assist with the preparation of cost allocation evidence using the OEB's 2025 Cost Allocation Model for Electricity Distributors issued on April 11, 2024. The relevant input and output sheets of the cost allocation model are filed under E7/T1/S1/A1.

2. WEIGHTING FACTORS

In order to arrive at weighting factors for the billing and collecting, NOW Inc. examined identifiable costs incurred in preparing and issuing bills, recording payment, and collecting in order to arrive at a cost per bill for each rate class. Weighting factors were calculated as costs relative to Residential which was assigned a weight of 1.0.

Table 1

Billing and Collecting Weighting Factors

Rate Class	Weighting Factor
Residential	1.0
General Service < 50 kW	1.0
General Service 50 to 4,999 kW	3.5
Street Lighting	0.6
Unmetered Scattered Load	0.7

The Services weighting factors used in NOW Inc.'s last cost of service (EB-2016-0096) were reviewed and deemed to be appropriate. The weighting factors were developed using engineering estimates of the average cost to install a service connection to each rate class.

Table 2

Services Weighting Factors

Rate Class	Weighting Factor
Residential	1.0
General Service < 50 kW	1.2
General Service 50 to 4,999 kW	1.7
Street Lighting	1.0
Unmetered Scattered Load	1.0

NOW Inc.'s installation costs per meter were calculated based on meter costs and burdened labour costs. Costs per meter are provided in Table 3.

Table 3

Meter Installation Costs

Meter	Cost
RE - Sensus INA2	$ 372.07
RE/Sm C - Sensus ISA2	$ 372.07
Sm. Com - Esler A3RL 7 JAW	$ 464.88
Sm. Com - Esler A3RL 13 JAW	$ 547.75
Sm. Com - Sensus Icon ADX7 JAW	$ 503.88
Mist - Esler A3KL 7 JAW	$ 579.13
Mist - Esler A3KL 13 JAW	$ 662.00
MicroFit Single Phase - Sensus ISA2 - Bi	$ 392.88
MicroFit 3 Phase - Elster A3KAL 7 JAW - Bi	$ 586.88

The lower-cost meters are primarily used by Residential and General Service < 50 kW customers and the higher cost meters are used by the General Service 50 to 4,999 kW rate class. Relative meter capital weightings are provided in Table 4 which are calculated after applying meter counts to rate classes.

Table 4

Meter Capital Weighting Factors

Rate Class	Weighting Factor
Residential	1.0
General Service < 50 kW	1.1
General Service 50 to 4,999 kW	1.8
Street Lighting	0.0
Unmetered Scattered Load	0.0

Meter reading weighting factors are calculated by comparing the cost per smart meter reading and the cost per MIST meter reading. Smart meter reading services are provided by Sense and MIST meter readings are provided by Utilismart. The resulting weighting factors are provided in Table 5.

Table 5

Meter Reading Weighting Factors

Rate Class	Weighting Factor
Residential	1.0
General Service < 50 kW	1.0
General Service 50 to 4,999 kW	14.7
Street Lighting	0.0
Unmetered Scattered Load	0.0

3. LOAD PROFILES

NOW Inc. has updated the load profiles for all rate classes. Load profiles were derived using weather-normalized 2022-2023 hourly load data; adjustments were made to align the 2023 load profiles with the proposed 2025 Load Forecast (i.e. consumption forecast). The weather-normalization process involves three steps:

a) Derive weather profile of a typical year;
b) Derive the impact of heating degree days ("HDD") and cooling degree days ("CDD") on hourly load; and

c) Adjust actual load to typical load with the degree day impacts.

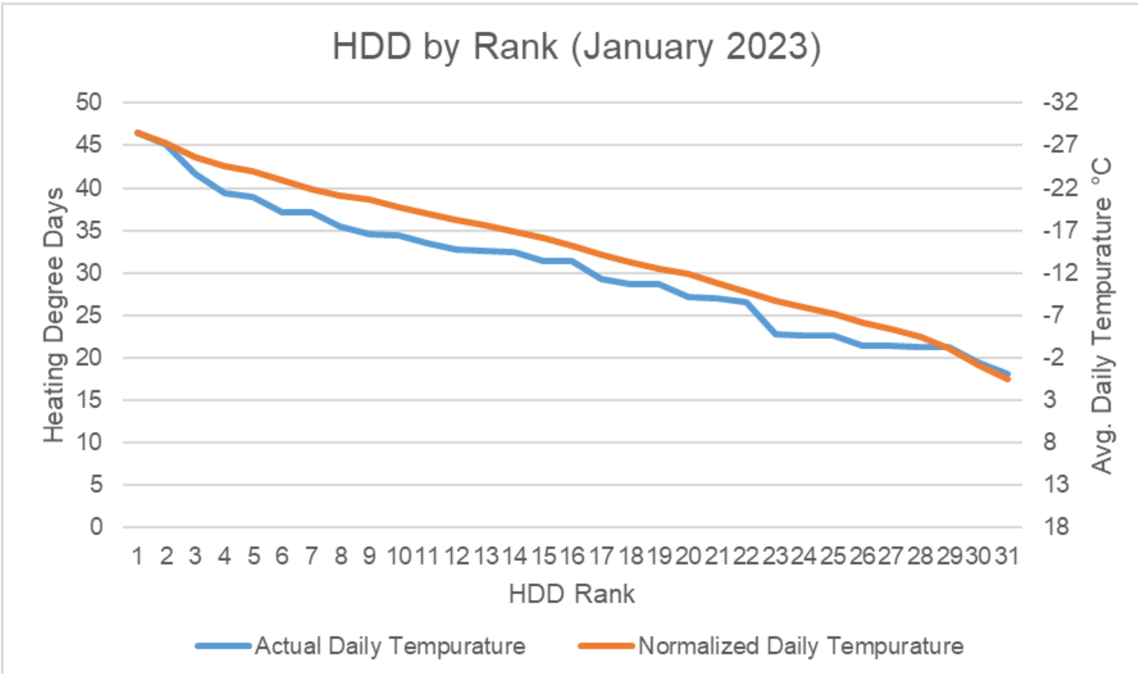
Derivation of Daily Temperatures

The weather profile of a typical year in NOW Inc's service territory is calculated using average daily temperatures from 2014 to 2023. Average daily temperatures are defined as the average highest to lowest daily temperatures within a month (i.e. average of the coldest January day in each January from 2014 to 2022), rather than average temperatures on a specific calendar date (i.e. the average temperature on each January 1st). This process maintains the shape of the load profiles by determining typical monthly peaks and lows without smoothing those peaks.

Average daily temperatures are derived by first ranking each day in each month from 2014 to 2023 from highest to lowest by HDD as measured at Environment Canada's Kapuskasing CDA Weather Station. Multiple HDDs and CDDs values were determined instead of the default 18°C. HDD and CDD base values are discussed in further detail in Exhibit 3. The average HDDs among equivalently ranked days within a given month are then used as the average HDD for that ranked day in that month. For example, the days in January 2014 are ranked from 1 to 31 by HDD and this is repeated for each year from 2015 to 2023. The average HDD of the January days ranked 1 is calculated to provide the typical highest HDD day in January. All days in January ranked 1 are assigned this calculated average HDD. This process is repeated for the January days ranked 2 to 31. NOW Inc. provides an example of average daily temperatures from 2014 to 2023 and actual temperatures in January 2023 ranked from 1 to 31 in Figure 1 below.

Figure 1

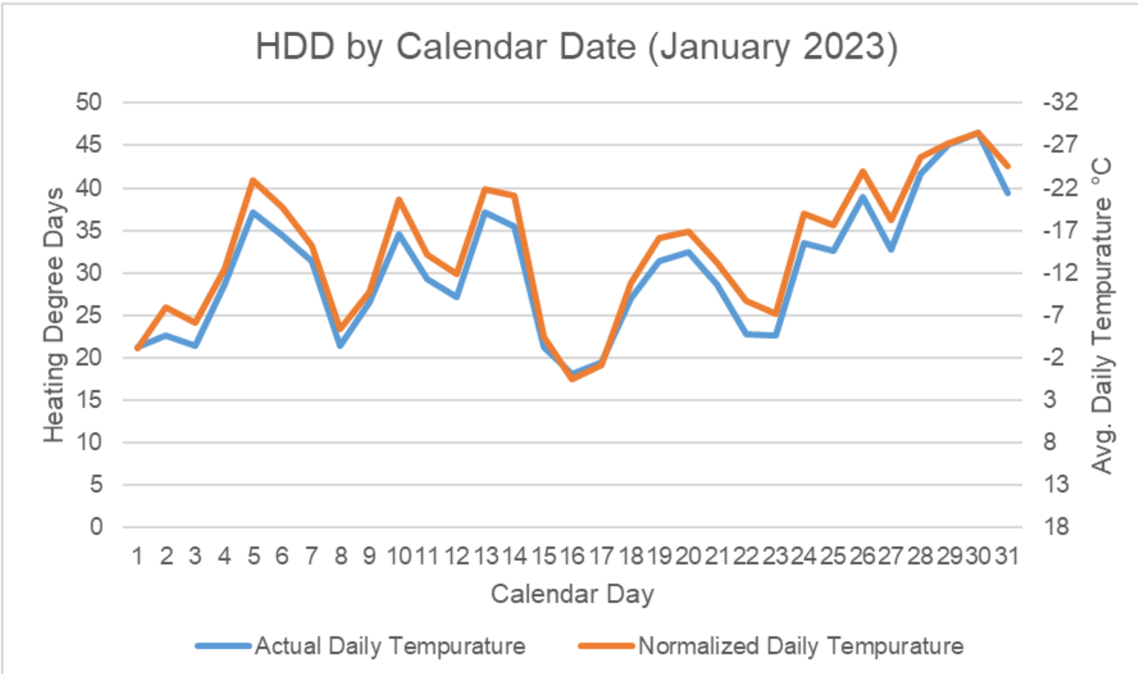
10-Year Avg. Daily HDD and Actual January 2023 HDD by Rank



Average daily temperatures reflect the January normal-weather profile in NOW Inc.'s service territory. Figure 2 below displays the same information by calendar date using the average and actual temperatures associated with each ranked day.

Figure 2

10-Year Avg. Daily HDD and Actual January 2023 HDD by Calendar Date



Typical daily CDDs are determined by the same ranking and averaging methodology described above, using average daily CDD data from 2014 to 2023. January 2023 was milder than average January temperatures, so the weather normalization process increases 2023 loads to reach weather-normalized loads.

Impact of HDD and CDD on Hourly Load

The impact of HDDs and CDDs on hourly load is calculated with a regression of two years of actual hourly loads (2022 and 2023) on daily HDDs and CDDs. The regression results provide the estimated impact of a change in degree days on load.

Temperatures impact load differently depending on the time of the day. Consequently, HDD and CDD variables are converted to interaction variables between degree days, the hour of the day, and whether the day is a weekday or a weekend/holiday. There are 24 variables for each weekday HDD, weekday CDD, weekend/holiday HDD, and weekend/holiday CDD equal to the actual degree days in the corresponding hour and 0 in all other hours. A set of 24 binary variables, equal to 1 in the corresponding hour and 0 in all other hours and a trend variable are also included. The resulting coefficients reflect the impact of one HDD or CDD that considers different impacts depending on the hour of the day and type of day.

Adjust Actual Load to Typical Load

Actual 2023 hourly load is adjusted by calculating the difference between actual daily temperatures and the corresponding ranked typical daily temperature (as identified in Figure 2) and applying the regression coefficient to the difference. The year 2023 was selected as the base year to scale to avoid somewhat irregular consumption patterns in 2022 caused by the COVID-19 pandemic that are expected to diminish by the 2023 Test Year.

After 2023 weather-normalized demand is derived for each hour, the load in each hour is adjusted by the same factor such that the sum of hourly loads is equal to the proposed 2025 Load Forecast (i.e. consumption forecast).

Table 6 below provides the calculations used to adjust actual January 1, 2023 weather variables to typical weather for the Residential class.

Table 6

January 1 Hour 12 Residential Example

Date	Hour	Temp °C	HDD (18)	HDD Rank	Average HDD at Rank	CDD	CDD Rank	Average CDD at Rank
		A	B = 18 – A	C	D	E	F	G
1-Jan	12	-3.4	21.4	29	23.0	0	3	0

Date	Hour	2023 Load (kW)	HDD Diff.	HDD18 Coef.	CDD Diff.	CDD12 Coef.	2023 Normal Load (kW)
		H	I = D - B	J	K = G - E	L	M = H + (I * J) + (K * L)
1-Jan	12	5,379	1.6	70.2	0	105.9	5,490

Date	Hour	2023 Normal Load (kW)	Sum of 2023 Normal Loads	2025 Forecast Consumption Excluding EVs & Heating	2023 to 2025 Load Adjustment	2025 Normal Load (kW) Excluding EV & Heating
		M	N	O	P = O / N	Q = M * P
1-Jan	12	5,490	38,935,790	41,061,738	1.054	5,790

Date	Hour	2025 Normal Load (kW) Excl. EV&H	2025 EV Load (kWh)	Hourly EV Load	2025 Heating Load	HDD in Hour	Hourly Heating Load (kWh)	Total 2025 Normal Load (kW)
		Q	R	S = R / 8760	T	U	V = T * U	W = Q + S + V
1-Jan	12	5,790	180,171	21	98,788	0.0266%	26	5,837

The HDD at noon on January 1st, 2023 was 21.4 HDD, which was the 29th highest HDD in the month. The 29th highest January HDD in each year from 2014 to 2023 was, on average, 23.0 HDD. The difference, 1.6 HDD, is multiplied by the weekend/holiday HDD Hour 12 coefficient of 70.2 kW/HDD from the load profile regression to produce the 111kW adjustment. This adjustment is applied to actual load in the noon hour of January 1, 2023 (5,379 kW) to reach the weather-normalized load (5,490 kW). The 2025 Residential load forecast, excluding additional EV and heating loads, is 5.4% higher than the sum of 2023 weather-normalized hourly loads and as such, the initial January 1, 2025 weather-normalized demand increases to 5,790 kW. Incremental EV load of 21 kW is added using a simplified assumption that demand will be equal in each hour.

Incremental hourly heating load is added by multiplying the total annual incremental heating load by the share of total weather-normal HDD in each hour for an addition of 26kW.

GS < 50 kW and GS > 50 kW load profiles are derived by the same methodology. The Street Light class is not weather sensitive and as such its loads are not weather-normalized. The USL class was assumed to have a constant load. After load profiles are derived for all classes, total system and class-specific peaks within each month are compiled to produce Coincident Peak ("CP") and Non-Coincident Peak ("NCP") figures used in Tab "I8 Demand Data" of the OEB's Cost Allocation Model. NOW Inc. provides a model illustrating how demand data was derived as "NOWI Load Profile Derivation".

4. CLASS SPECIFIC DETAILS

4.1. New Customer Class

NOW Inc. is not proposing to include a new rate class. NOW Inc.'s current large General Service class is defined as General Service 50 to 4,999 kW. Should one or more of its General Service 50 to 4,999 kW customers exceed 5,000 kW, NOW Inc. proposes to continue to apply General Service 50 to 4,999 kW charges until its next rebasing application at which point it expects to propose a new rate class for these customers.

4.2. Elimination of Customer Class

NOW Inc. does not propose to eliminate any customer class.

4.3. Standby Rates

NOW Inc. is proposing to introduce a Standby Power Service Classification for accounts that have load displacement generation. NOW Inc. does not currently have any customers that would take service under this rate classification, however, it has a small number of large customers within its General Service 50 to 4,999 kW rate class that contribute a material share of distribution revenues. Should one of these customers install load displacement generation it may materially impact NOW Inc.'s financial position and would adversely impact the rates of its other customers following NOW Inc.'s next cost of service application.

NOW Inc. proposes to set the Standby Power Service Classification rates equal to its proposed General Service 50 to 4,999 kW charges. NOW Inc. will apply this charge to the volume of load transfer capacity contracted by the generating facility when the customer's loads are less than contracted demand. The proposed standby rate is modelled on Entegrus Powerlines Inc.' standby charge, which was most recently approved in EB-2015-0061.

In the absence of a standby rate, should a customer install load displacement generation it would not materially reduce NOW Inc.'s cost to serve the customer. NOW Inc. would need to maintain the customer's current capacity to provide backup service during planned maintenance of the generation facility and unplanned outages of the facility. It is therefore reasonable to apply a standby charge equal to the proposed General Service 50 to 4,999 kW service charges.

4.4. Micro FIT

NOW Inc. is not proposing to include microFIT as a separate class in the cost allocation model in 2025.

4.5. Embedded Distributor Class

NOW Inc. confirms that it is not a host utility or an embedded distributor.

Attachment 1 (of 1):

Cost Allocation Model - Revenue Worksheets

Ontario Energy Board

2025 Cost Allocation Model

EB-2024-0046

Sheet O1 Revenue to Cost Summary Worksheet - Initial Application

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

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$3,976,708	$2,723,293	$706,056	$334,308	$204,467	$8,584
mi	Miscellaneous Revenue (mi)	$247,849	$166,861	$31,158	$40,494	$8,801	$535
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	**$4,224,557**	**$2,890,154**	**$737,214**	**$374,802**	**$213,268**	**$9,119**
	Factor required to recover deficiency (1 + D)	1.3670					
	Distribution Revenue at Status Quo Rates	$5,436,226	$3,722,786	$965,190	$457,005	$279,510	$11,735
	Miscellaneous Revenue (mi)	$247,849	$166,861	$31,158	$40,494	$8,801	$535
	Total Revenue at Status Quo Rates	**$5,684,075**	**$3,889,648**	**$996,348**	**$497,499**	**$288,311**	**$12,270**
	Expenses						
di	Distribution Costs (di)	$2,070,052	$1,313,908	$285,066	$320,433	$145,871	$4,774
cu	Customer Related Costs (cu)	$1,445,246	$1,129,149	$148,276	$64,877	$100,203	$2,742
ad	General and Administration (ad)	$1,035,614	$714,774	$128,983	$119,051	$70,597	$2,210
dep	Depreciation and Amortization (dep)	$444,406	$278,270	$63,822	$85,153	$16,290	$872
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0
INT	Interest	$272,533	$167,299	$39,462	$54,560	$10,650	$563
	Total Expenses	**$5,267,851**	**$3,603,399**	**$665,608**	**$644,073**	**$343,612**	**$11,159**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$416,223	$255,505	$60,268	$83,326	$16,265	$859
	Revenue Requirement (includes NI)	$5,684,075	$3,858,904	$725,876	$727,399	$359,877	$12,019
		Revenue Requirement Input equals Output					

Ontario Energy Board

2025 Cost Allocation Model

EB-2024-0046

Sheet O1 Revenue to Cost Summary Worksheet - Initial Application

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-Regular	7 Street Light	9 Unmetered Scattered Load
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$11,864,424	$7,439,224	$1,699,471	$2,250,238	$452,356	$23,135
gp	General Plant - Gross	$4,400,288	$2,702,923	$637,027	$879,223	$172,033	$9,082
accum dep	Accumulated Depreciation	($6,169,719)	($3,940,237)	($875,118)	($1,113,309)	($229,671)	($11,384)
co	Capital Contribution	($155,283)	($99,655)	($22,185)	($26,858)	($6,272)	($313)
	Total Net Plant	$9,939,710	$6,102,255	$1,439,195	$1,989,294	$388,446	$20,520
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$13,561,454	$6,786,927	$2,939,609	$3,727,729	$80,359	$26,830
	OM&A Expenses	$4,550,912	$3,157,831	$562,325	$504,360	$316,671	$9,725
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	*$18,112,366*	*$9,944,758*	*$3,501,933*	*$4,232,089*	*$397,031*	*$36,555*
	Working Capital	$1,358,427	$745,857	$262,645	$317,407	$29,777	$2,742
	Total Rate Base	$11,298,138	$6,848,111	$1,701,840	$2,306,701	$418,223	$23,262
		Rate Base Input equals Output					
	Equity Component of Rate Base	$4,519,255	$2,739,245	$680,736	$922,680	$167,289	$9,305
	Net Income on Allocated Assets	$416,223	$286,248	$330,740	($146,574)	($55,301)	$1,110
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0
	Net Income	$416,223	$286,248	$330,740	($146,574)	($55,301)	$1,110
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	100.00%	100.80%	137.26%	68.39%	80.11%	102.09%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($1,459,518)	($968,750)	$11,338	($352,597)	($146,608)	($2,900)
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$30,743	$270,472	($229,900)	($71,566)	$251
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.21%	10.45%	48.59%	-15.89%	-33.06%	11.93%

Ontario Energy Board

2025 Cost Allocation Model

EB-2024-0046

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

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	9
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$15.05	$15.07	$62.58	$4.85	$8.92
Customer Unit Cost per month - Directly Related	$19.45	$19.57	$84.54	$6.25	$11.56
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$50.26	$50.69	$116.42	$17.15	$39.83
Existing Approved Fixed Charge	$43.82	$38.17	$230.33	$9.19	$19.35

Exhibit 7: Cost Allocation

Tab 2 (of 2): Class Revenue Requirements

CLASS REVENUE REQUIREMENTS

The allocated costs by rate class for the 2017 Cost of Service filing and 2025 updated study are provided in the following Table 7 below.

Table 1
Allocated Costs

Rate Class	2017 Allocated Costs	%	2025 Allocated Costs	%
Residential	$ 2,528,613	68.7%	$ 3,858,904	67.9%
General Service < 50 kW	$ 603,864	16.4%	$ 725,876	12.8%
General Service 50-4,999 kW	$ 331,484	9.0%	$ 727,399	12.8%
Street Lighting	$ 209,689	5.7%	$ 359,877	6.3%
Unmetered Scattered Load	$ 6,427	0.2%	$ 12,019	0.2%
Total	**$ 3,680,077**	**100.0%**	**$ 5,684,075**	**100.0%**

REVENUE TO COST RATIOS

The results of a cost allocation study are presented in the form of revenue to cost ratios. The ratio is shown by rate class and is the percentage of revenue collected by rate class compared to the costs allocated to the class. The percentage identifies the rate classes that are being subsidized and those that are over-contributing. A ratio less than 100% indicates the costs allocated to the rate class exceeds the revenues from the rate class. A ratio greater than 100% indicates revenues from the rate class exceed the costs allocated to the class.

Table 8 provides NOW Inc.'s revenue to cost ratios from the 2017 Application, the updated 2025 cost allocation study and the proposed 2025 to 2027 ratios.

Table 2
Revenue to Cost Ratios

Rate Class	2017 Approved	2025 Cost Allocation Results	2025 Proposed Ratios	2026 Proposed Ratios	2027 Proposed Ratios	Range of Reasonableness	
						Min	Max
Residential	96.91%	100.80%	100.80%	100.80%	100.80%	85%	115%
General Service < 50 kW	116.12%	137.26%	120.00%	119.03%	116.39%	80%	120%
General Service 50-4,999 kW	104.54%	68.39%	89.28%	89.28%	89.28%	80%	120%
Street Lighting	120.00%	80.11%	72.72%	74.67%	80.00%	80%	120%
Unmetered Scattered Load	83.09%	102.09%	102.09%	102.09%	102.09%	80%	120%

The 2025 cost allocation study indicates the revenue to cost ratios for the General Service < 50 kW and General Service 50 to 4,999 kW rate classes are outside the Board's range. For 2025, it is proposed the two General Service ratios be brought within the Board's range.

The Street Lighting rate class would have total bill impacts in excess of 10% without rate mitigation. The ratios in the table above reflect rate mitigation for this class by reducing the Street Lighting revenue to cost ratio and increasing the ratio of the class with the lowest revenue to cost ratio, the General Service 50 to 4,999 kW rate class. In subsequent years, the Street Lighting ratio increases with corresponding decreases to the General Service < 50 kW rate class as it is the rate class with the highest revenue to cost ratio. This is discussed further in E8/T4/S1.

Table 9 provides information on calculated class revenue, which is consistent with Tab 11 of the RRWF. The resulting 2025 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 3
Rate Class Revenues

Rate Class	2025 Base Revenue at Existing Rates	2025 Proposed Revenues with Uniform Rate Increase	2025 Proposed Revenues	Miscellaneous Revenues
Residential	$ 2,723,293	$ 3,722,786	$ 3,722,786	$ 166,861
General Service < 50 kW	$ 706,056	$ 965,190	$ 839,893	$ 31,158
General Service 50-4,999 kW	$ 334,308	$ 457,005	$ 608,915	$ 40,494
Street Lighting	$ 204,467	$ 279,510	$ 252,896	$ 8,801
Unmetered Scattered Load	$ 8,584	$ 11,735	$ 11,735	$ 535
Total	**$ 3,976,708**	**$ 5,436,226**	**$ 5,436,226**	**$ 247,849**

Attachment 1 (of 1):

RRWF Sheet 11

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Cost Allocation and Rate Design

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

Stage in Application Process: **Initial Application**

A) Allocated Costs

	Name of Customer Class (3) From Sheet 10. Load Forecast	Costs Allocated from Previous Study (1)	%	Allocated Class Revenue Requirement (1) (7A)	%
1	Residential	$ 2,528,613	68.71%	$ 3,858,904	67.89%
2	General Service 50 W	$ 603,864	16.41%	$ 725,876	12.77%
3	General Service 50-4,999 W	$ 331,484	9.01%	$ 727,399	12.80%
4	Street Lighting	$ 209,689	5.70%	$ 359,877	6.33%
5	Unmetered Scattered Load	$ 6,427	0.17%	$ 12,019	0.21%
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 3,680,077	100.00%	**$ 5,684,075**	100.00%
		Service Revenue Requirement (from Sheet 9)		**$ 5,684,073.86**	

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

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

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

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 2,723,293	$ 3,722,786	$ 3,722,786	$ 166,861
2	General Service 50 W	$ 706,056	$ 965,190	$ 839,893	$ 31,158
3	General Service 50-4,999 W	$ 334,308	$ 457,005	$ 608,915	$ 40,494
4	Street Lighting	$ 204,467	$ 279,510	$ 252,896	$ 8,801
5	Unmetered Scattered Load	$ 8,584	$ 11,735	$ 11,735	$ 535
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 3,976,708	$ 5,436,226	$ 5,436,226	$ 247,849

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

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
Column 7C - The OEB-issued cost allocation model calculates "1+d" on wor sheet O-1, cell C22. "d" is defined as Revenue Deficiency Revenue at Current Rates.

(6)

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

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2017	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential	96.91%	100.80%	100.80%	85 - 115
2	General Service 50 W	116.12%	137.26%	120.00%	80 - 120
3	General Service 50-4,999 W	104.54%	68.39%	89.28%	80 - 120
4	Street Lighting	120.00%	80.11%	72.72%	80 - 120
5	Unmetered Scattered Load	83.09%	102.09%	102.09%	80 - 120
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2020 with further adjustments to move within the range over two years, the Most Recent Year would be 2023. However, the ratios in 2023 would be equal to those after the adjustment in 2022.

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

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

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

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2025	2026	2027	
1	Residential	100.80%	100.80%	100.80%	85 - 115
2	General Service 50 W	120.00%	119.03%	116.39%	80 - 120
3	General Service 50-4,999 W	89.28%	89.28%	89.28%	80 - 120
4	Street Lighting	72.72%	74.67%	80.00%	80 - 120
5	Unmetered Scattered Load	102.09%	102.09%	102.09%	80 - 120
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(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2025 that is outside of the OEB s policy range for any customer class. Table D will show that the distributor is li ely to enter into the 2026 and 2027 Price Cap IR models, as necessary. For 2026 and 2027, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2026 (in the current Revenue Cost Ratio Adjustment Wor form, Wor sheet C1.1 Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as Rebalance .