Exhibit 7:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 2): Cost Allocation Study

OVERVIEW OF COST ALLOCATION

This Exhibit 7 includes information on cost allocation study requirements, load profile data, class revenue requirements and revenue-to-cost ratios.

Kingston Hydro has followed the guidance in the OEB's cost allocation policy reports of November 28, 2007 *"Report of the Board on Application of Cost Allocation for Electricity Distributors*"[1] and March 31, 2011 "*Review of Electricity Distribution Cost Allocation Policy*"[2] and has prepared a Cost Allocation Study for the 2023 Test Year using the OEB's Cost Allocation Model ("CA Model"). The CA Model has been used to determine the proportion of Kingston Hydro's total revenue requirement that is recoverable from each customer class for Test Year 2023. The revenue-to-cost ratio for each customer class for the test year has been determined using the customer class revenues over costs.

Exhibit 7 Tab 1 Schedule 1 Attachment 1 is the *"Kingston Hydro 2023 Cost Allocation Study*" report prepared by Elenchus Research Associates Inc. (Elenchus) on behalf of Kingston Hydro. The report includes information on updated load profile data.

The completed CA Model is filed along with this Application in live Excel format.

[1] EB-2007-0667
[2] EB-2010-0219

Weighting Factors for Service and Billing Costs

As outlined in the report, *"Review of Electricity Distribution Cost Allocation Policy"*[3], the OEB stated that weighting factors are included in the Cost Allocation model to ensure that certain costs related to customer classes are properly assigned to the respective classes. The OEB also stated that distributors are expected to develop their own weighting factors to be used in the Cost Allocation model. Distributors should only use the default weighting factors under exceptional situations.

Kingston has developed its own weighting factors for allocation of certain costs and has used them in the CA Model. Kingston has used its own weighting factors for Services, and Billing and Collecting.

Services (Account 1855): The Services weighting factors were developed based on Kingston Hydro conducting an evaluation of the costs of installing a typical service for each customer class, are provided in the following Table 1.

Table 1: Services Weighting Factors

Services Weighting Factors	Residential	GS <50 kW	GS>50-4,999 kW	Large Use	Street Lighting	Unmetered Scattered Load
	1.0	2.5	7.8	11.5	0.0	0.2

Billing and Collecting: The Billing and Collecting weighting factors used in Kingston's cost allocation model was updated according to Kingston's billing and collecting information for each customer class. The following Table 2 provides the billing and collecting weighting factors:

[3] Ibid, Section 2.6.4

Table 2: Billing and Collecting Weighting Factors

Billing and Collecting Weighting Factors	Residential	GS <50 kW	GS>50-4,999 kW	Large Use	Street Lighting	Unmetered Scattered Load
	1.0	1.0	11.7	11.5	0.8	0.8

Unmetered Scattered Load (USL) Customer Class

Kingston has consistent with its past cost of service applications and custom IR application, included as part of this 2023 COS Application, a separate USL rate class in the 2023 CA Model and on the proposed Tariff of Rates and Charges.

Street Lighting Adjustment Factor

Per the OEB's June 15, 2015 letter, with regard to the report *"Report of the Board on Review of the Board's Cost Allocation Policy for Unmetered Loads"* [4], the OEB established that a "street lighting adjustment factor" is to be used to allocate costs to the street lighting rate class for primary and line transformer assets.

In Kingston Hydro's 2023 CA Model, the street lighting adjustment factor of 2.01 used in Kingston Hydro's 2016-2020 Custom IR has been updated to 2.06, based upon most recent survey data available from Kingston Hydro's geographical information system (GIS) records.

[4] EB-2012-0383, December 19, 2013

Standby Power

Kingston Hydro has an approved on a final basis Standby Power rate classification. No change is proposed in the methodology on which this rate is based.

New or Eliminated Customer Classes

No new customer classifications and no elimination of customer classes is proposed in this Application.

MicroFIT class

Kingston Hydro has a MicroFIT class listed on its tariff of rates and charges however the class has not been included in the CA Model as a separate class. The OEB establishes a generic rate which Kingston Hydro has adopted and currently the generic rate is $4.55[5].

[5] Review of Fixed Monthly Charge for microFIT Generator Service Classification - OEB File Numbers
EB-2009-0326 and EB-2010-0219, February 25, 2021

Attachment 1 (of 1):

Cost Allocation Report

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Toronto, Ontario M5C 2B5
elenchus.ca

Kingston Hydro 2023
Cost Allocation Report

Report prepared by
Elenchus Research Associates Inc.

June 2022

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1 INTRODUCTION

Kingston Hydro Corporation ("Kingston Hydro") has prepared its 2023 Cost of Service Application based on a forward 2023 Test Year. The relevant filing requirements for this Application are set out in Chapter 2 of the April 18, 2022 update to the *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications* ("Filing Requirements").

Section 2.7.1 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements on page 41 state:

> *A completed cost allocation study using the OEB-approved methodology, or the distributor's study and model must be filed. This filing must reflect the forecasted test year loads and costs and be supported by appropriate explanations and live Excel spreadsheets. The most current update of the model is available on the OEB's website. Sheets 11 and 13 of the RRWF must also be completed.*

Kingston Hydro asked Elenchus Research Associated ("Elenchus") to assist it by preparing an appropriate cost allocation study for its 2023 Cost of Service rate application.

In addressing the cost allocation issues, Elenchus was guided by the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[3] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report") in which the Board narrowed some revenue to cost ratio ranges, and committed to further consultations on unmetered and standby loads, as well as the Board's decisions in various electricity distributor cost of service proceedings that addressed relevant issues.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2023 forward test year, the primary purpose of the cost allocation study ("CA Study") is to determine the proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, Kingston Hydro's prospective year CA Study for the 2023 Test Year is based on an allocation of the 2023 Test Year costs (i.e., the 2023 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Given a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

1.2 KINGSTON HYDRO'S 2016-2020 COST ALLOCATION

The last cost allocation study filed by Kingston Hydro was in its 2016-2020 Custom IR Application (EB-2015-0083). Five models were prepared in that proceeding, one for each year from 2016 to 2020, as it was a Custom IR application. In this matter (EB-2022-0044), Kingston Hydro is submitting a Cost of Service application based on a 2023 Test Year so only one model reflecting the single test year is required.

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into four additional sections. Section 2 provides an overview of the Kingston Hydro CA Study, explaining the model run included in the study, as well as the load and cost information used for the run. Section 3 explains the methodology used to develop the 2023 Kingston Hydro model by documenting each step taken in completing the model. Section 4 summarizes the results of the Kingston Hydro CA Study, showing the class revenue requirements and revenue to cost ratios generated by the CA model. Section 5 shows the fixed charge unit costs per month and the fixed charge boundary values as calculated in the cost allocation models for 2023.

2 OVERVIEW OF THE KINGSTON HYDRO 2023 CA STUDY

2.1 LOAD AND CUSTOMER INFORMATION

The CA model has been prepared using the following load and load profile information:

- Annual Loads (kW and kWh, as appropriate) and customer counts
  - The 2023 load forecast and customer counts by class being used by Kingston in its application were also used for the 2023 CA model.
- Hourly Load Profile
  - Kingston Hydro has updated its load profile data based on three years of actual hourly load data (2019-2021). Hourly loads were weather-normalized based on a multivariate regression analysis utilizing Heating and Cooling Degree days, among other variables. Weather normalization and adjustments to match forecast loads with the 2023 consumption forecast were applied to 2019 loads to avoid the impacts of COVID-19 on 2020 and 2021 consumption patterns that are expected to significantly decline by the 2023 Test Year. The methodology is described fully in Section 3.1.

2.2 COST INFORMATION

As noted earlier, the Filing Requirements mandate that the cost allocation models be prepared on the basis of prospective test year information. In the case of Kingston Hydro, the financial information for the 2023 Test Year has been prepared at the USoA level. Kingston Hydro tracks the USoA of assets that correspond to capital contributions so the assignment of capital contributions, accumulated depreciation of capital contributions, and capital contribution depreciation expense within tab ‘I4 BO Assets’ is based on specified forecast figures, and not a proration of total amounts.

3 COST ALLOCATION STUDY METHODOLOGY

This section documents Elenchus's methodology for the Kingston Hydro Cost Allocation Study, the 2023 CA Model.

3.1 HOURLY LOAD PROFILE

In a letter dated June 12, 2015[1], the OEB stated that it expected distributors to be mindful of material changes to load profiles and to propose updates in their respective cost of service applications when warranted. In its 2016-2020 Custom IR application, Kingston Hydro used the load profiles provided by Hydro One in its cost allocation models. Those load profiles were scaled to the 2016-2020 consumption forecasts. The Hydro One profiles were based on 2004 data, and consumption patterns have changed since then due to factors such as technology, macroeconomic changes, conservation programs and time of use pricing.

Kingston Hydro has updated the load profiles for all rate classes. Load profiles were derived using weather-normalized 2019-2021 hourly load data and adjustments were made to align the weather-normalized 2019 load profiles with the proposed 2023 Load Forecast (i.e. consumption forecast). The weather-normalization process involves three steps:

a) Deriving weather profile of a typical year;
b) Deriving 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.

3.1.1 DERIVATION OF DAILY TEMPERATURES

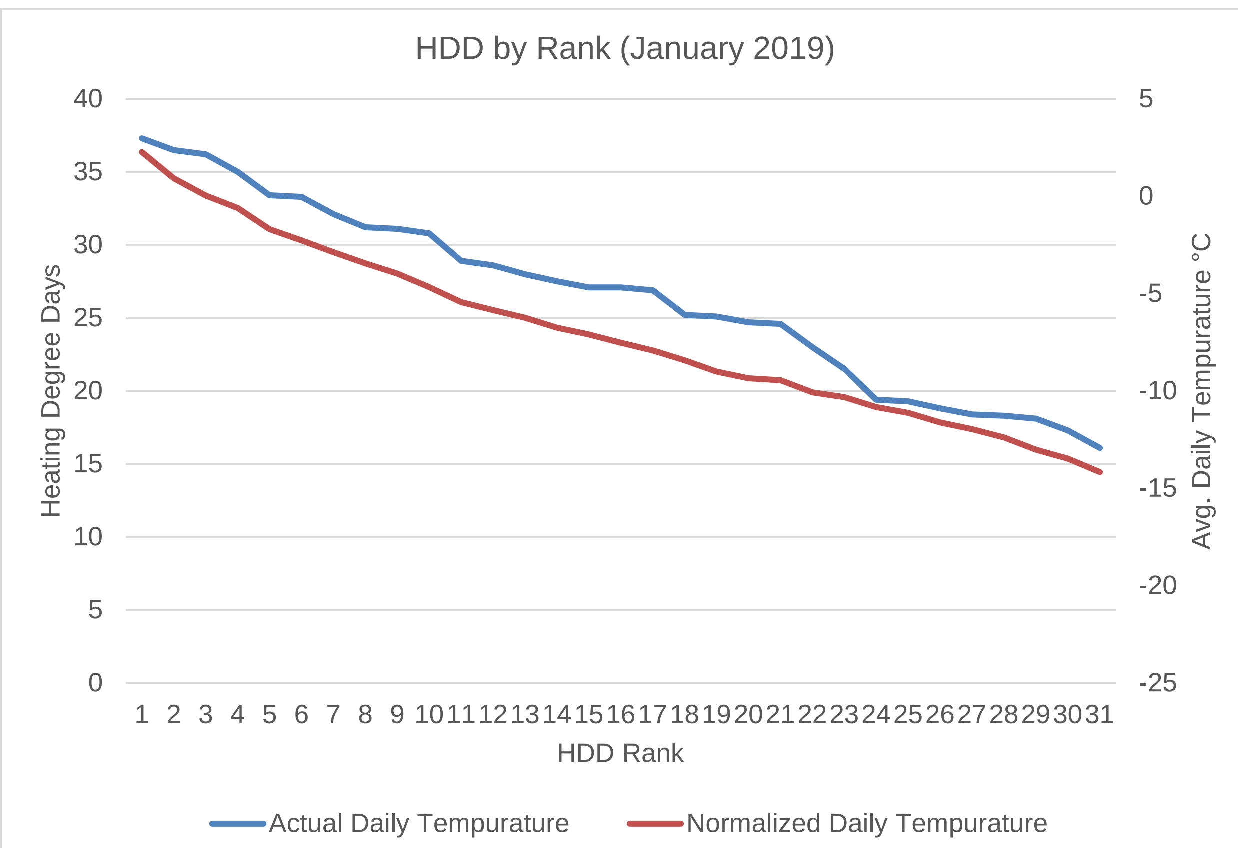
The weather profile of a typical year in Kingston Hydro's service territory is calculated using average daily temperatures from 2012 to 2021. Average daily temperatures are defined as the average highest to lowest daily temperatures within a month (i.e. average of the coldest January day in each January from 2012 to 2021), 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.

[1] EB-2012-0083, Review of Cost Allocation Policy for Unmetered Loads, Issuance of New Cost Allocation Policy for Street Lighting Rate Class

Average daily temperatures are derived by first ranking each day in each month from 2012 to 2021 from highest to lowest by HDD as measured at Environment Canada's Kingston Climate Weather Station. 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 2012 are ranked from 1 to 31 by HDD and this is repeated for each year from 2013 to 2021. 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. Elenchus provides an example of average daily temperatures from 2012 to 2021 and actual temperatures in January 2021 ranked from 1 to 31 in Figure 1 below.

Figure 1

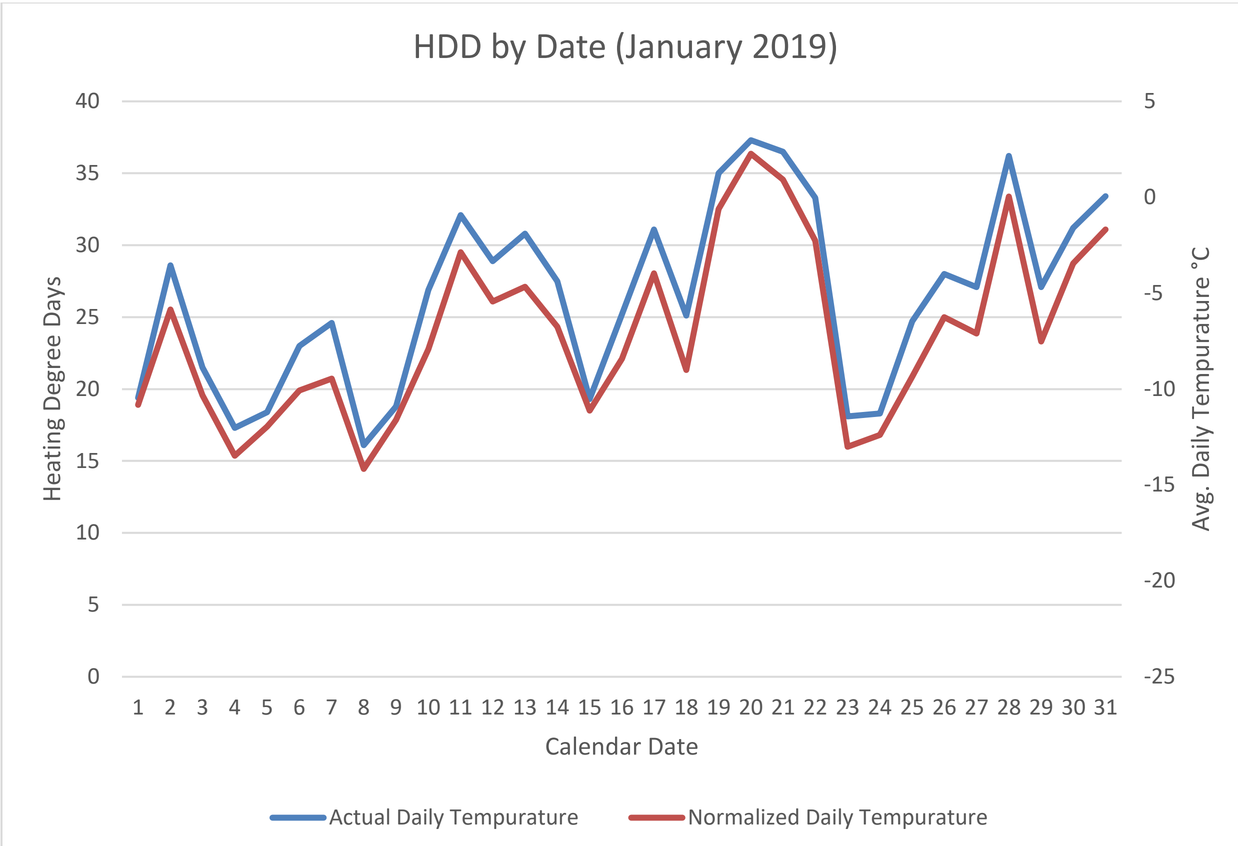
10-Year Avg. Daily HDD and Actual January 2019 HDD by Rank



Average daily temperatures reflect the January normal-weather profile in Kingston Hydro'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 2019 HDD by Calendar Date



Typical daily CDDs are determined by the same ranking and averaging methodology described above, using average daily CDD data from 2012 to 2021. Temperatures in January 2019 were colder than average January temperatures, so the weather normal values are lower than actuals and the normalization process reduces 2019 loads to reach weather-normalized loads.

3.1.2 Impact of HDD and CDD on Hourly Load

The impact of HDDs and CDDs on hourly load is calculated with a regression of three years of actual hourly loads (2019 to 2021) 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 and consequently HDD and CDD variables are converted to interaction variables between degree days and the hour of the day. There are 24 variables for each of HDD and 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; COVIDHDD and

COVIDCDD variables equal to 0 in all days until March 16, 2020 and equal to the relevant HDD or CDD in each hour thereafter; a trend variable; a Weekend or Holiday binary variable; and a Summer binary variable are also included.[2] The resulting coefficients reflect the impact of one HDD or CDD that considers different impacts depending on the hour of the day.

3.1.3 Adjust Actual Load to Typical Load

Actual 2019 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 2019 was selected as the base year to scale to avoid irregular consumption patterns in 2020 and 2021 caused by the COVID-19 pandemic that are expected to diminish by the 2023 Test Year.

After 2019 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 2023 Load Forecast (i.e. consumption forecast).

Table 1 below provides the calculations used to adjust actual January 1, 2019 weather variables to typical weather for the Residential class. The Residential class uses HDD at base 16°C and CDD at base 16°C, as these variables provided better statistical results than other temperatures considered.

[2] There are a total of 77 independent variables, however, the set of 72 for hourly HDD, hourly CDD and binary Hour variables have only three non-zero values in each observation. The values are 0 in each hour other than the HDD, CDD, and binary hour variables that correspond to the hour of the observation. This regression is similar to 24 regressions, one for each hour of the day.

Table 1
January 1 Hour 1 Residential Example

Date	Hour	Temp °C	HDD	HDD Rank	Average HDD at Rank	CDD	CDD Rank	Average CDD at Rank
		A	B = 16 - A	C	D	E	F	G
1-Jan	1	-1.4	17.4	24	16.9	0	8	0

Date	Hour	2019 Load (kW)	HDD Diff.	HDD1 Coef.	CDD Diff.	CDD1 Coef.	2019 Normal Load (kW)
		H	I = D - B	J	K = G - E	L	M = H + (I * J) + (K * L)
1-Jan	1	20,113	0.5	628.9	0	761.9	19,799

Date	Hour	2019 Normal Load (kW)	Sum of 2019 Normal Loads	2023 Forecast Consumption	2019 to 2021 Load Adjustment	2021 Normal Load (kW)
		M	N	O	P = O / N	Q = M * P
1-Jan	1	19,799	183,010,111	186,841,333	1.0209	20,213

The HDD on January 1st, 2019 was 17.4 HDD, which was the 24th highest HDD in the month. The 24th highest January HDD in each year from 2012 to 2021 was, on average, 16.9 HDD. The difference, -0.5 HDD, is multiplied by the "HDD Hour 1" coefficient of 628.9 from the load profile regression to produce the -314.4 kW adjustment. This adjustment is applied to actual load in the first hour of January 1, 2019 (20,113 kW) to reach the weather-normalized load (19,799 kW). The 2023 Residential load forecast is 2.1% higher than the sum of 2019 weather-normalized hourly loads and as such, the January 1, 2023 weather-normalized demand increases to 20,213 kW.

General Service < 50 kW, General Service > 50 kW, and Large Use 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 hourly load was assumed to have a constant load. Elenchus provides a model illustrating how demand data was derived as "Kingston_CA_Load_Profile_Derivation_Example'". This model provides detailed calculations for the Residential load profile, however, derivations for the other classes have been removed to reduce the size of the model, which exceeds 100MB.

3.2 DEMAND ALLOCATORS

The demand allocators used in the Kingston Hydro 2023 CA model were derived using the hourly load profiles as described in Section 3.1. Using the 2023 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.3 2023 DEMAND DATA

The demand allocators derived in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2023 Kingston Hydro CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values for GS > 50 and Large User customer classes are not equal to the full class NCP values since not all customers in these customer classes use these facilities. For the same reason, the Secondary 1NCP, 4NCP, and 12NCP values for the GS < 50 customer class is not equal to the full class NCP values. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2016-2020 CA Models.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Kingston Hydro cost allocation model is shown in Table 2, below.

Table 2
Revenue to Cost Ratios

Customer Class	Kingston-2016	Kingston-2023 Status Quo Rates	Board Target Range
Residential	99.06%	104.10%	85-115
GS < 50 kW	116.05%	124.06%	80-120
GS > 50 Regular	96.65%	82.05%	80-120
Large Use	93.39%	82.65%	85-115
Street Light	81.29%	72.73%	80-120
USL	118.07%	110.92%	80-120
Total	**100.00%**	**100.00%**	

The Kingston Hydro 2023 ratios (at Status Quo rates) reflect the impact of changes in throughput by class as well as changes in costs from 2020 through the 2023 forecast Test Year.

Table 3 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 3
Revenue Responsibility by Rate Class

Customer Class	Kingston 2016		Kingston 2023	
	$	%	$	%
Residential	$8,186,789	59.8%	$8,713,498	58.1%
GS < 50 kW	$1,584,711	11.6%	$1,859,886	12.4%
GS > 50 Regular	$3,115,806	22.8%	$3,345,725	22.3%
Large Use	$575,857	4.2%	$758,876	5.1%
Street Light	$208,206	1.5%	$278,875	1.9%
USL	$21,435	0.2%	$30,864	0.2%
Total	**$13,692,803**	**100.0%**	**$14,987,724**	**100.0%**

5 FIXED CHARGE RATES

The Kingston Hydro cost allocation model produced the following customer unit cost per month values:

Table 4
2023 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC[3] Adjustment
Residential	$4.88	$7.62	$16.19
GS < 50 kW	$5.21	$8.22	$16.70
GS > 50 Regular	$58.58	$98.90	$128.97
Large Use	$63.04	$123.64	$402.87
Street Light	$0.63	$1.13	$8.02
USL	$1.61	$2.89	$8.71

In accordance with Board policy, the following boundary values would apply for the fixed monthly service charge:

Table 5
2023 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	$4.88	$16.19	$27.24	$4.88	$27.24
GS < 50 kW	$5.21	$16.70	$16.16	$5.21	$16.70
GS > 50 Regular	$58.58	$128.97	$117.69	$58.58	$128.97
Large Use	$63.04	$402.87	$5,419.98	$63.04	$5,419.98
Street Light	$0.63	$8.02	$1.37	$0.63	$8.02
USL	$1.61	$8.71	$6.78	$1.61	$8.71

[3] PLCC: 'Peak Load Carrying Capacity'

Exhibit 7: Cost Allocation

Tab 2 (of 2): Class Revenue Requirements

CLASS REVENUE REQUIREMENTS

Kingston Hydro's class revenue requirements, in the format required for filing cost allocation information, are detailed in the four tables of Tab "11.Cost_Allocation" of the RRWF, filed along with this Application in live Excel format.

REVENUE TO COST RATIOS

The results of a cost allocation study are typically presented in the form of revenue-to-cost (or revenue-to-expense) ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following Table 1 provides status quo ratios and proposed ratios for 2023, 2024, 2025.

Table 1: Rate Class Status Quo and Proposed Ratios

Rate Class	Status Quo Ratios	Proposed 2023 Ratios	Proposed 2024 Ratios	Proposed 2025 Ratios	Policy Range	
					Min	Max
Residential	104.10%	104.10%	104.10%	104.10%	85%	115%
GS < 50 kW	124.06%	120.00%	117.70%	117.55%	80%	120%
GS 50 to 4,999 kW	82.05%	84.54%	84.54%	84.54%	80%	120%
Large Use	82.65%	85.00%	85.00%	85.00%	85%	115%
Street Lighting	72.73%	63.33%	79.00%	80.00%	80%	120%
USL	110.92%	110.92%	110.92%	110.92%	80%	120%

The 2023 Cost Allocation Study indicates the revenue-to-cost ratios for the Large Use and Street Lighting rate classes are below their respective minimum revenue-to-cost ratios. The General Service < 50 kW rate class ratio is above the maximum 120% revenue-to-cost ratio. As a first approximation, the classes below the minimum were increased to the minimum (85% for Large Use and 80% for Street Lights) and revenues to come from the General Service < 50 kW rate class were reduced to the point where the revenue-to-cost ratio decreased to 120%.

As described in Exhibit 8, the total bill impacts for the Street Lighting rate class would exceed 10% so rates for the class are adjusted such that total bills increases are exactly 10% in 2023 and 2024, and a further increase in 2025 brings the class revenue to cost ratio of exactly 80%. Overall, after adjustments to General Service < 50 kW, Large Use, and Street Lighting (including mitigation), there is a revenue deficiency.

Kingston Hydro proposes to make up this deficiency by increasing revenues to come from the class with the lowest revenue-to-cost ratio, the General Service 50 to 4,999 kW class. This causes an increase in the revenue-to-cost ratio of that class from 82.05% to 84.54%. Of the total 2.49% increase to the General Service 50 to 4,999 kW ratio, 1.13% ($37,621) of the increase is caused by reductions to General Service < 50 kW revenues (partially offset by an increase in Large Use revenues) and the remaining 1.36% ($45,003) is attributable to Street Lighting rate mitigation.

As Street Lighting revenues continue to increase in 2024 and 2025, Kingston Hydro proposes to reduce revenues to come from the class with the highest revenue-to-expense ratio, the General Service < 50 kW rate class, to maintain revenue neutrality. Overall, General Service < 50 kW rate classes will decline from 124.06% status quo to 117.55% in 2025.