SYNERGY NORTH CORPORATION

EXHIBIT 7
COST ALLOCATION

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TABLES

LIST OF ATTACHMENTS

7.1 COST ALLOCATION STUDY REQUIREMENTS

7.1.1 OVERVIEW

On September 29, 2006, the Ontario Energy Board ("the "Board") issued its directions on *Cost Allocation Methodology for Electricity Distributors* (the "Directions"). On November 15, 2006, the Board issued the *Cost Allocation Information Filing Guidelines for Electricity Distributors* (the "Guidelines"), the Cost Allocation Model (the "Model") and the User Instructions (the "Instructions") for the Model. SNC has prepared this Application to be consistent with SNC's understanding of the Directions, the Guidelines, the Model, and the Instructions.

On March 31, 2011, the Board issued additional guidance entitled *Review of Electricity Distribution Cost Allocation Policy* (EB-2009-0261). For the purposes of this Application, SNC has followed the cost allocation policies outlined in the Board's March 31, 2011, Cost Allocation Report, the Board's letter dated June 12, 2015, with regard to the treatment of Street Lighting connections, and the 2023 Cost Allocation Model version ("CA Model") issued on May 27, 2022.

In this application, SNC has used the 2023 Cost Allocation Model version of the cost allocation model, the latest version available when the application was prepared, and submitted the cost allocation study to reflect 2024 test year costs, customer numbers and demand values. The 2024 demand values were based on weather-normalized 2022 hourly demand values by rate class adjusted to the weather-normalized load forecast used to design rates. SNC has developed weighting factors as outlined below based on analyzing the costs allocated by each weighting factor.

7.2 WEIGHTING FACTORS

The following discussion outlines the detail associated with determining the class revenue requirements.

7.2.1 WEIGHTING FACTOR FOR SERVICES (ACCOUNT 1855)

As per the suggested methodology on the Cost Allocation instruction sheet, the Residential class was given a weighting factor of 1.0. The cost of General Service < 50 kW installations is somewhat higher than Residential is they may require after-hours attendance to mitigate against interruptions during normal business hours. Additional time is required to ensure the demand data is programmed and monitored appropriately. General Service > 50 kW and General Service > 1000 kW installation costs may also require after-hours attendance to mitigate against interruptions during normal business hours.

Additional time is also required to ensure the demand data is programmed and monitored appropriately. Additionally, these installations require additional planning and preparation time due to the complexity of the metering equipment, so the weighting factor is higher than that of the General Service < 50 kW.

For Street Lighting, Sentinel Lighting, and Unmetered Scattered Load, SNC does not have assets in account 1855 associated with these classes, which causes the assigned weighting factor to be set at 0.

Table 7-1: Services Weighting Factors - 1855

Rate Class	Factor
Residential	1.0
General Service < 50 kW	1.9
General Service > 50 to 999 kW	8.0
General Service > 1000 kW	8.0
Street Lighting	0.0
Sentinel Lighting	0.0
Unmetered Scattered Load	0.0

7.2.2 Weighting Factor for Billing and Collection

In determining the weighting factors for Billing and Collecting, an analysis of Accounts 5305 – 5340, was conducted. Each expense within these accounts was allocated to each rate class with an expense-specific weighting factor. The weighted cost was then multiplied by the number of customers in each class to calculate the expense attributed to each class for each expense line item. The total expense per line per class was then calculated and divided by the total number of customers in the class to determine the portion of expense related to each class. With the Residential factor set to one, each of the other class factors was calculated.

The billing and collecting labour were weighted according to the hours required to bill an average cycle route for each class. The residential routes, on average, require approximately 5 hours to bill per month, while the GS>50 take approximately 15 hours per month to bill. This is due to the complexity of the data required to produce a bill. The labour allocation expense was derived by the supervisor, who produces the bills regularly using average route sizes during a regular billing month.

Through this analysis, SNC was able to align the Billing and Collection expenses to each rate class and thus calculate the factors shown below in Table 7-2.

TABLE 7-2: BILLING & COLLECTING WEIGHTING FACTORS

Rate Class	Factor
Residential	1.0
General Service < 50 kW	1.0
General Service > 50 to 999 kW	1.8
General Service > 1000 kW	1.5
Street Lighting	1.0
Sentinel Lighting	0.0
Unmetered Scattered Load	0.0

7.2.3 INSTALLATION COST PER METER

SNC 's installation costs per meter were calculated based on current meter costs, labour rates, truck rates, and IT costs, if applicable. The installed costs of SNC 's general service meters include higher capital and installation costs, as shown in Table 7-3 below.

TABLE 7-3: METER CAPITAL INSTALLATION COSTS

Rate Class	Installation Cost per Meter
Smart Meters Residential	$340
Smart Meters - GS < 50 kW	$750
Demand without IT (usually three-phase)	$935
Demand with IT and Interval Capability - Secondary	$3,170
Demand with IT and Interval Capability - Primary	$32,570

7.2.4 WEIGHTING FACTORS FOR METER READING

SNC completed an analysis of the costs included in the meter reading and assigned the costs to the appropriate type of meter based on the nature of the cost. Based on this activity analysis, SNC calculated the overall cost per meter and assigned a weighting of 1 for the meter reading costs related to smart AMI meters.

All SNC meters are read either through the AMI or MV90. SNC reviewed the costs associated with meter reading and assigned costs to reading either AMI Smart Meters or MV90. The majority of meter reading costs, such as software and outside service provider costs, are clearly identifiable as either Smart Meter-related and MV90-related. However, some costs, such as labour, are assigned based on judgment in which class is assigned an equal share per customer. The resulting weightings for each type of meter are 1.0 for Smart Meters and 72 for MV90 meters. The weighting factors, weighted by type of meter in each customer class, are set out in Table 7-4 below.

ODS and Honeywell costs are allocated evenly between Residential, GS<50 and GS 50-999 classes. ITRON costs are allocated solely to the GS>1000 class. As there are only 15 GS>1000 customers, the weighed meter reading costs are significantly higher.

TABLE 7-4: METER READING WEIGHTING FACTORS

Line No.	Rate Class	Factor
1	Residential	1.0
2	General Service < 50 kW	1.0
3	General Service > 50 to 999 kW	1.0
4	General Service > 1000 kW	72.0

7.3 SUMMARY OF RESULTS AND PROPOSED CHANGES

The data used in the updated cost allocation study is consistent with SNC's cost data that support the proposed 2024 revenue requirement outlined in this Application. Consistent with the Guidelines, SNC's assets were broken out into primary and secondary distribution functions using current information on the distribution system. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to SNC, its engineering records, and its customer and financial information systems. An Excel version of the updated cost allocation study has been included with the filed Application.

Capital contributions, depreciation, and accumulated depreciation by USoA are consistent with the information provided in the 2024 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2024 customer forecast outlined in Exhibit 3.

7.3.1 LOAD PROFILE DATA

In a letter dated June 12, 2015, 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 last Cost of Service application (EB-2016-0105), TBHEDI used the load profiles provided by Hydro One in its cost allocation model. The Hydro One profiles were based on 2004 data, and consumption patterns have changed due to factors such as technology, macroeconomic changes, conservation programs and time of use pricing.

SNC has updated the load profiles for all rate classes. Load profiles were derived using weather-normalized 2019, 2021, and 2022 hourly load data; adjustments were made to align the 2022 load profiles with the proposed 2024 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.

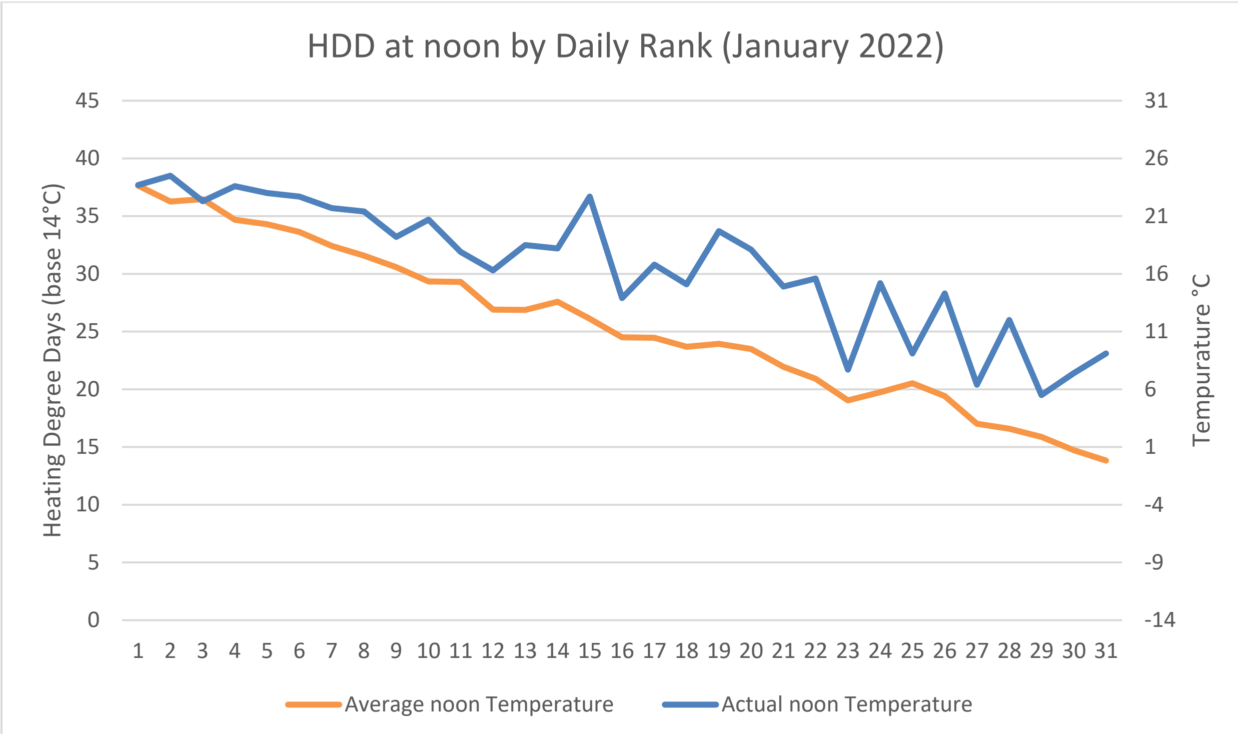
Derivation of Hourly Temperatures

The weather profile of a typical year in SNC's service territory is calculated using average hourly temperatures from 2013 to 2022. Average hourly temperatures are defined as the average temperature at each hour of the day of the highest to lowest daily temperatures within a month (i.e., an average of the coldest January day in each January from 2013 to 2022), rather than average temperatures on a specific calendar date (i.e. the average temperature on each January 1st). This process, described in more detail below, maintains the shape of the load profiles by determining typical peaks and lows without smoothing those peaks.

Average hourly temperatures are derived by first ranking each day in each month from 2013 to 2022 from highest to lowest by HDD as measured at both Environment Canada's Thunder Bay CS weather station and Environment Canada's Kenora Weather Airport weather station. HDDs and CDDs rely on the same base values as the proposed load forecast for each class instead of the default 18°C. HDD and CDD base values are discussed in detail in Exhibit 3. The average HDDs in each hour 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 2013 are ranked from 1 to 31 by HDD, and this is repeated for each year from 2014 to 2022. The average HDD in each hour of the January days ranked 1 (the coldest January day in each year) is calculated to provide the typical hourly HDD in the highest HDD day in January. All days in January ranked 1 are assigned the same calculated average HDD for each hour. This process is repeated for the January days ranked 2 to 31. SNC provides an example of average daily temperatures from 2013 to 2022 and actual temperatures in January 2024 ranked from 1 to 31 in Figure 7.1 below.

Figure 7.1

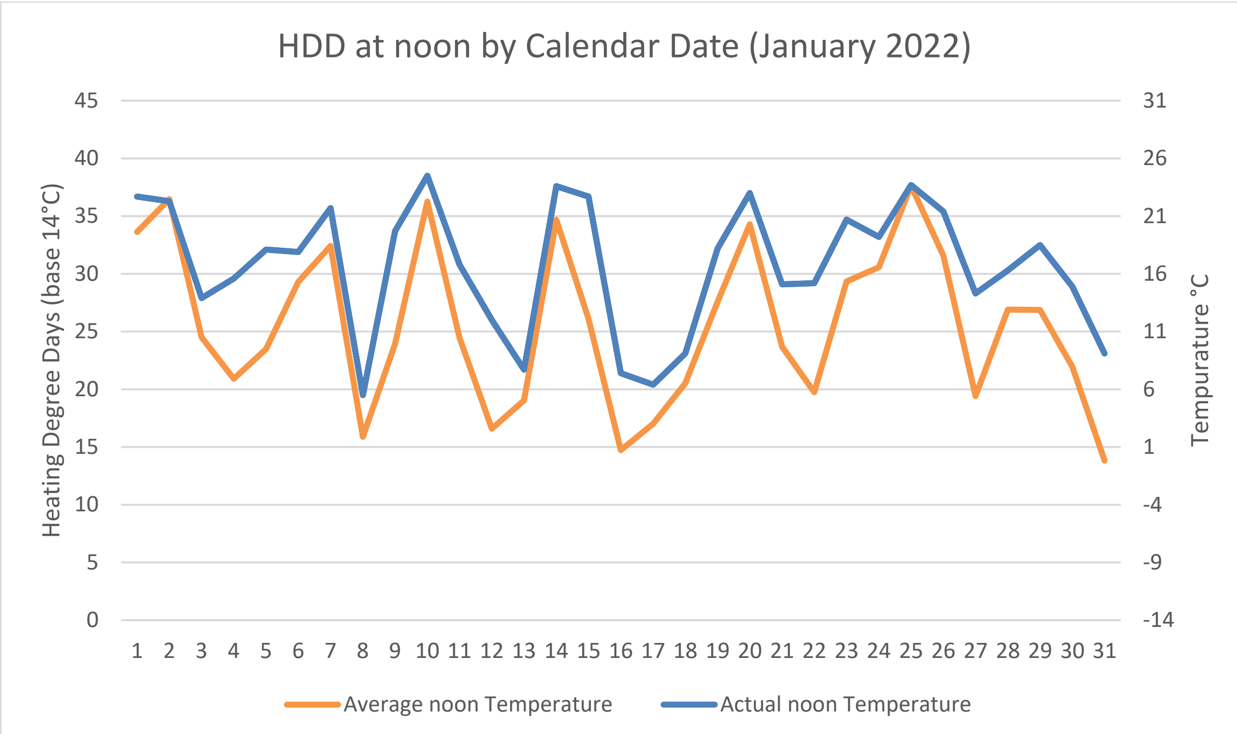
10-Year Avg. Daily HDD and Actual January 2022 HDD by Rank



Average daily temperatures reflect the January normal-weather profile in both SNC's service territories (Kenora and Thunder Bay). Since days are ranked by daily average temperatures and not hourly average temperatures, the actual temperature at noon (or any given hour) does not necessarily decline in each ranked day. Figure 7.2 below displays the same information organized by calendar date using the average and actual temperatures associated with each ranked day.

Figure 7.2

10-Year Avg. Daily HDD and Actual January 2022 HDD by Calendar Date



Typical daily CDDs are determined by the same ranking and averaging methodology described above, using average daily CDD data from 2013 to 2022. January 2022 was colder than average January temperatures, so the weather normalization process reduced 2022 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 three years of actual hourly loads (2019, 2021, and 2022) 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 type of 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. Overall, there are 121 variables, 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

The actual 2022 hourly load is adjusted by calculating the difference between actual hourly temperatures and the corresponding ranked typical hourly temperature (as identified in Figure 7.2) and applying the regression coefficient to the difference. After 2022 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). This process is done separately for each rate zone.

Table 7-5 below provides the calculations used to adjust actual January 1, 2022, weather variables to typical weather for the Residential class in Thunder Bay.

TABLE 7-5: JANUARY 1 NOON RESIDENTIAL EXAMPLE

Date	Hour	Temp °C	HDD	HDD Rank	Average HDD at Rank	CDD	CDD Rank	Average CDD at Rank
		A	B = 14 – A	C	D	E	F	G
1-Jan	13	-22.7	36.7	6	33.7	0	26	0

Date	Hour	2022 Load (kW)	HDD Diff.	WEH HDD13 Coef.	CDD Diff.	WEH CDD13 Coef.	2022 Normal Load (kW)
		H	I = D – B	J	K = G – E	L	M = H + (I * J) + (K * L)
1-Jan	13	61,145	-3.0	941	0	1,606	58,341

Date	Hour	2022 Normal Load (kW)	The sum of 2022 Normal Loads	2024 Forecast Consumption	2022 to 2024 Load Adjustment	2024 Normal Load (kW)
		M	N	O	P = O / N	Q = M * P
1-Jan	13	58,341	333,751,869	341,222,755	1.0224	59,647

The HDD at noon on January 1st, 2022, was 36.7 HDD, which was the 6th-highest HDD day in the month. The 6th highest January HDD at noon in each year from 2013 to 2022 was, on average, 33.7 HDD. The difference, -3.0 HDD, is multiplied by the “Weekend/Holiday HDD14 Hour 13” coefficient of 941 from the load profile regression to produce the -2,804 kW adjustment. This adjustment is applied to the actual load in the 13th (noon-1pm) hour of January 1, 2022 (61,145 kW) to reach the weather-normalized load (58,341kW). The 2024 Thunder Bay Residential load forecast is 2.24% higher than the sum of 2022 weather-normalized hourly loads, and as such, January 1, 2024, weather-normalized demand increases to 59,647 kW.

General Service < 50 kW, General Service 50 to 999 kW, and General Service 1,000 to 4,999 kW load profiles are derived by the same methodology. The Street Light and Sentinel Light classes are not weather sensitive, and as such, their loads are not weather-normalized. The USL hourly load was assumed to have a constant load in each hour of each month. 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. SNC provides a model illustrating how demand data was derived as Attachment 7-A. This model provides detailed calculations for the Thunder Bay Residential load profile. However, derivations for the other classes and historic weather data have been removed to reduce the size of the model.

7.4 CLASS SPECIFIC DETAILS

7.4.1 New Customer Class

SNC is not proposing to include a new customer class.

7.4.2 Elimination of Customer Class

SNC does not propose to eliminate any customer class.

7.4.3 Unmetered Loads

SNC plans to communicate with unmetered load customers, including Street Lighting customers, to assist them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers with the filing of this application. The rationale for the timing of the communication is to provide the customers with as accurate results as possible while still providing them with the ability to become involved in the review process of the application should they so choose.

7.4.4 Stand By Rates

SNC currently does not have stand-by rates, and it is not proposing to establish stand-by rates in this Application.

7.4.5 MicroFIT

SNC is not proposing to include MicroFIT as a separate class in the cost allocation model in 2024.

7.4.6 Embedded Distributor Class

SNC confirms that it is not a host utility or an embedded distributor, and no partially embedded distributor status exists. Accordingly, SNC is not required to complete Board Appendix 2-Q.

7.5 CLASS REVENUE REQUIREMENTS

The allocated cost by rate class for the 2024 Cost of Service filing and OEB-approved results are provided in the following Table 7-6 below. The OEB-approved values are the sum of KHEC 2011 OEB-approved with IRM escalations (I-X) to 2017 plus the TBHEDI 2017 OEB approved allocations.

Table 7-6: Allocated Cost

Rate Class	2017 TBHEDI plus escalated 2011 KHEC OEB Approved Cost Allocation Study	%	Cost Allocated in the 2024 Study	%
Residential	$16,437,424	59.74%	$23,418,963	60.64%
General Service < 50 kW	$4,473,952	16.23%	$5,840,297	15.12%
General Service > 50 to 999 kW	$4,404,703	16.14%	$6,156,754	15.94%
General Service > 1,000 kW	$1,717,693	6.22%	$2,319,531	6.01%
Street Lighting	$370,546	1.35%	$770,892	2.00%
Sentinel Lighting	$20,640	0.07%	$21,187	0.05%
Unmetered Scattered Load	$67,450	0.25%	$92,736	0.24%
Total	**$27,492,408**	**100.0%**	**$38,620,360**	**100.0%**

7.6 REVENUE-TO-COST RATIOS

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. The ratio is shown by rate classification and is the distribution revenue collected by rate classification, at the proposed test year load forecast with a status quo rate increase, compared to the costs allocated to the rate class. 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.

In the March 31, 2011, Cost Allocation Report, the Board established what it considered to be the appropriate ranges of revenue-to-cost ratios which are summarized in Table 7-7 below. In addition, Table 7-7 provides SNC's revenue-to-cost ratios from the 2017 Application, the updated 2024 cost allocation study and the proposed 2024 and 2025-2028 ratios.

TABLE 7-7: REVENUE-TO-COST RATIOS

Rate Class	2011 KHEC Board Approved	2017 TBHEDI Board Approved	2024 Updated Cost Allocation Study	2024 Proposed Ratios	2025-2028 Proposed Ratios	Board Targets Min	Board Targets Max
Residential	101.2%	98.2%	99.5%	99.5%	99.5%	85%	115%
General Service < 50 kW	80.0%	112.4%	117.8%	115.8%	114.4%	80%	120%
General Service > 50 to 999 kW	125.0%	86.9%	87.4%	88.7%	88.7%	80%	120%
General Service > 1,000 kW		109.3%	105.0%	105.0%	105.0%	80%	120%
Street Lighting	76.6%	143.2%	64.9%	69.6%	80.0%	80%	120%
Sentinel Lighting		94.1%	90.9%	90.5%	90.5%	80%	120%
Unmetered Scattered Load	138.0%	115.3%	110.9%	110.9%	110.9%	80%	120%

The 2024 cost allocation study indicates that the revenue-to-cost ratios for the Street Lighting class are outside the Board's range. There are large total bill increases (>10%) for the Street Lighting and Sentinel Lighting rate classes so SNC's proposal is to reduce the revenue-to-cost ratios for these classes by increasing the revenue-to-cost ratio of the class with the lowest revenue-to-cost ratio, the General Service 50 to 999 kW rate class. Please see Exhibit 8 Section 8.14 Rate Mitigation for more details. It is proposed that the Street Lighting ratios be brought within the Board's range, however, this will be done over two years to mitigate large total bill increases in 2024.

The following Table 7-8 provides information on calculated class revenue, which is consistent with RRWF, Tab 11 Cost Allocation, and Calculated Class Revenues. The resulting 2024 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

TABLE 7-8: CALCULATED CLASS REVENUE

Rate Class	2024 Base Revenue at Existing Rates	2024 Proposed Base Revenue Allocated at Existing Rates	2024 Proposed Base Revenue	Miscellaneous Revenue
Residential	$17,149,399	$21,631,154	$21,631,154	$1,669,600
General Service < 50 kW	$5,154,363	$6,501,384	$6,384,764	$379,306
General Service > 50 to 999 kW	$3,945,356	$4,976,420	$5,056,716	$405,797
General Service > 1,000 kW	$1,795,450	$2,264,666	$2,264,666	$169,790
Street Lighting	$343,247	$432,950	$469,353	$67,143
Sentinel Lighting	$13,992	$17,649	$17,571	$1,612
Unmetered Scattered Load	$76,213	$96,131	$96,131	$6,759
Total	**$28,478,021**	**$35,920,354**	**$35,920,354**	**$2,700,006**

EXHIBIT 7

ATTACHMENT 7 - A

2023 COST ALLOCATION MODEL

SYNERGY NORTH CORPORATION

Ontario Energy Board

2023 Cost Allocation Model

EB-2023-0052

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	987,726,571

Total kWs from Load Forecast	1,195,976

Deficiency/sufficiency (RRWF 8. cell F51)	- 7,442,333

Miscellaneous Revenue (RRWF 5. cell F48)	2,700,006

			1	2	3	5	7	8	9
	ID	**Total**	**Residential**	**GS <50**	**GS >50**	**Intermediate**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data									
Forecast kWh	**CEN**	987,726,571	379,789,070	168,043,431	284,545,343	147,571,558	5,592,860	96,035	2,088,274
Forecast kW	**CDEM**	1,195,976			706,551	473,245	15,924	258	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		585,175			111,930	473,245			
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**	987,726,571	379,789,070	168,043,431	284,545,343	147,571,558	5,592,860	96,035	2,088,274
Existing Monthly Charge			$27.88	$32.21	$277.81	$3,283.57	$1.392	$8.96	$9.66
Existing Distribution kWh Rate				$0.0181					$0.0125
Existing Distribution kW Rate					$3.4897	$3.1450	$7.2279	$7.1927	
Existing TOA Rate					$0.60	$0.60			
Additional Charges									
Distribution Revenue from Rates		$28,829,126	$17,149,399	$5,154,363	$4,012,514	$2,079,397	$343,247	$13,992	$76,213
Transformer Ownership Allowance		$351,105	$0	$0	$67,158	$283,947	$0	$0	$0
Net Class Revenue	**CREV**	$28,478,021	$17,149,399	$5,154,363	$3,945,356	$1,795,450	$343,247	$13,992	$76,213

Thunder Bay	kWh	**341,222,755**	144,147,634	247,097,013	147,571,558	5,217,474	96,035	1,919,602	
	kW			612,569	473,245	14,760	258		
	Customers/Conne	46,447	4,758	404	15	13,228	113	395	
	$/kWh		0.0199					0.0132	
	$/kW			3.7313	3.145	7.4973	7.1927		
	$/Cust.	27.30	30.49	229.50	3,283.57	1.25	8.96	9.09	
	TB Revenue	15,216,162	4,609,416	3,397,337	2,079,397	309,074	13,992	68,479	25,693,857
Kenora	kWh	38,566,315	23,895,798	37,448,329		375,386		168,672	
	kW			93,981		1,164			
	Customers/Conne	4,808	729	60		428		37	
	$/kWh		0.01					0.00	
	$/kW			1.91		3.81			
	$/Cust.	33.51	43.45	600.92		5.79		15.76	
	Kenora Revenue	1,933,236	544,948	615,177	-	34,173	-	7,734	3,135,268

Ontario Energy Board

2023 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet -

	ID	Total	1 Residential	2 GS <50	3 GS >50	5 Intermediate	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$351,786	$237,174	$53,022	$61,590	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$152,951	$103,119	$23,053	$26,778				
Number of Bills	CNB	688,428	615,060	65,843.90	5,568.08	180	48.00	1,176.00	552.00
Number of Devices	CDEV						13,656		
Number of Connections (Unmetered)	CCON	14,201					13,656	113	432
Total Number of Customers	CCA	57,369	51,255	5,487	464	15	4	98	46
Bulk Customer Base	CCB	57,770	51,255	5,487	464	15	4	113	432
Primary Customer Base	CCP	58,615	51,255	5,487	464	15	849	113	432
Line Transformer Customer Base	CCLT	58,615	51,255	5,487	464	15	849	113	432
Secondary Customer Base	CCS	57,770	51,255	5,487	464	15	4	113	432
Weighted - Services	CWCS	65,512	51,255	10,425	3,712	120	-	-	-
Weighted Meter -Capital	CWMC	23,423,168	17,426,697	4,115,244	1,392,677	488,550	-	-	-
Weighted Meter Reading	CWMR	58,286	51,255	5,487	464	1,080	-	-	-
Weighted Bills	CWNB	691,072	615,060	65,844	9,845	278	46	-	-

Bad Debt Data

		Total	Residential	GS <50	GS >50	Intermediate	Street Light	Sentinel	Unmetered Scattered Load
Historic Year:	2019	339,979	287,076	38,196	14,707				
Historic Year:	2020	343,334	230,002	86,805	26,527				
Historic Year:	2021	372,046	194,444	34,065	143,536				
Three-year average		**351,786**	**237,174**	**53,022**	**61,590**	**-**	**-**	**-**	**-**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	51,255	320,688	51,255	320,688
Street Light	13,656	5,314	13,656	5,314

Street Lighting Adjustment Factors	
Primary	16.0780
Line Transformer	16.0780

Ontario Energy Board

2023 Cost Allocation Model

EB-2023-0052

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

			1	2	3	5	7	8	9
Customer Classes		Total	Residential	GS <50	GS >50	Intermediate	Street Light	Sentinel	Unmetered Scattered Load
		CP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	176,450	77,216	30,322	45,611	21,812	1,232	23	235
Bulk Delivery CP	BCP1	176,450	77,216	30,322	45,611	21,812	1,232	23	235
Total Sytem CP	DCP1	176,450	77,216	30,322	45,611	21,812	1,232	23	235
4 CP									
Transformation CP	TCP4	625,406	266,890	109,061	169,653	76,135	2,657	45	964
Bulk Delivery CP	BCP4	625,406	266,890	109,061	169,653	76,135	2,657	45	964
Total Sytem CP	DCP4	625,406	266,890	109,061	169,653	76,135	2,657	45	964
12 CP									
Transformation CP	TCP12	1,816,477	729,530	317,591	492,692	268,589	5,120	91	2,863
Bulk Delivery CP	BCP12	1,816,477	729,530	317,591	492,692	268,589	5,120	91	2,863
Total Sytem CP	DCP12	1,816,477	729,530	317,591	492,692	268,589	5,120	91	2,863
NON CO_INCIDENT PEAK									
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP									
Classification NCP from Load Data Provider	DNCP1	195,847	84,362	31,775	47,911	30,187	1,329	23	260
Primary NCP	PNCP1	195,847	84,362	31,775	47,911	30,187	1,329	23	260
Line Transformer NCP	LTNCP1	158,070	84,362	31,775	40,321		1,329	23	260
Secondary NCP	SNCP1	158,070	84,362	31,775	40,321		1,329	23	260
4 NCP									
Classification NCP from Load Data Provider	DNCP4	759,314	320,688	125,467	186,977	119,774	5,314	91	1,004
Primary NCP	PNCP4	759,314	320,688	125,467	186,977	119,774	5,314	91	1,004
Line Transformer NCP	LTNCP4	609,920	320,688	125,467	157,357		5,314	91	1,004
Secondary NCP	SNCP4	609,920	320,688	125,467	157,357		5,314	91	1,004
12 NCP									
Classification NCP from Load Data Provider	DNCP12	2,053,686	838,669	346,056	511,697	338,131	15,942	272	2,919
Primary NCP	PNCP12	2,053,686	838,669	346,056	511,697	338,131	15,942	272	2,919
Line Transformer NCP	LTNCP12	1,634,493	838,669	346,056	430,635		15,942	272	2,919
Secondary NCP	SNCP12	1,634,493	838,669	346,056	430,635		15,942	272	2,919

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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

			1	2	3	5	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS >50	Intermediate	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$28,478,021	$17,149,399	$5,154,363	$3,945,356	$1,795,450	$343,247	$13,992	$76,213
mi	Miscellaneous Revenue (mi)	$2,700,006	$1,669,600	$379,306	$405,797	$169,790	$67,143	$1,612	$6,759
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	**$31,178,027**	**$18,818,999**	**$5,533,669**	**$4,351,153**	**$1,965,240**	**$410,390**	**$15,605**	**$82,972**
	Factor required to recover deficiency (1 + D)	1.2613							
	Distribution Revenue at Status Quo Rates	$35,920,354	$21,631,154	$6,501,384	$4,976,420	$2,264,666	$432,950	$17,649	$96,131
	Miscellaneous Revenue (mi)	$2,700,006	$1,669,600	$379,306	$405,797	$169,790	$67,143	$1,612	$6,759
	Total Revenue at Status Quo Rates	**$38,620,360**	**$23,300,754**	**$6,880,690**	**$5,382,217**	**$2,434,455**	**$500,093**	**$19,261**	**$102,889**
	Expenses								
di	Distribution Costs (di)	$11,509,393	$6,567,339	$1,802,276	$2,043,676	$804,181	$255,345	$6,771	$29,806
cu	Customer Related Costs (cu)	$2,743,270	$2,345,707	$295,799	$89,238	$10,928	$1,542	$12	$45
ad	General and Administration (ad)	$7,181,998	$4,486,642	$1,058,087	$1,077,313	$411,326	$130,069	$3,437	$15,123
dep	Depreciation and Amortization (dep)	$6,138,149	$3,677,782	$971,391	$987,736	$362,726	$119,707	$3,511	$15,296
INPUT	PILs (INPUT)	$940,862	$540,072	$145,865	$166,820	$62,202	$22,503	$635	$2,765
INT	Interest	$4,132,366	$2,372,052	$640,656	$732,691	$273,197	$98,836	$2,789	$12,144
	Total Expenses	**$32,646,037**	**$19,989,594**	**$4,914,075**	**$5,097,474**	**$1,924,560**	**$628,001**	**$17,155**	**$75,179**
	Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$5,974,323	$3,429,369	$926,222	$1,059,280	$394,971	$142,891	$4,032	$17,557
	Revenue Requirement (includes NI)	$38,620,360	$23,418,963	$5,840,297	$6,156,754	$2,319,531	$770,892	$21,187	$92,736
		Revenue Requirement Input equals Output							

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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	5 Intermediate	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$298,292,662	$175,332,143	$47,024,534	$50,538,686	$17,806,090	$6,641,070	$176,011	$774,129
gp	General Plant - Gross	$27,066,182	$15,705,539	$4,207,715	$4,707,533	$1,699,353	$650,200	$17,946	$77,896
accum dep	Accumulated Depreciation	($134,005,780)	($79,681,001)	($21,462,514)	($22,138,622)	($7,662,440)	($2,689,067)	($67,697)	($304,438)
co	Capital Contribution	($41,617,221)	($25,361,922)	($6,552,645)	($6,582,236)	($1,967,010)	($1,020,151)	($25,279)	($107,978)
	Total Net Plant	$149,735,843	$85,994,759	$23,217,091	$26,525,360	$9,875,992	$3,582,051	$100,981	$439,609
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$109,695,350	$42,310,091	$18,644,050	$31,528,235	$16,351,246	$619,701	$10,641	$231,385
	OM&A Expenses	$21,434,661	$13,399,688	$3,156,162	$3,210,227	$1,226,435	$386,955	$10,220	$44,974
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$131,130,010*	*$55,709,779*	*$21,800,213*	*$34,738,462*	*$17,577,681*	*$1,006,656*	*$20,860*	*$276,359*
	Working Capital	$9,834,751	$4,178,233	$1,635,016	$2,605,385	$1,318,326	$75,499	$1,565	$20,727
	Total Rate Base	$159,570,594	$90,172,992	$24,852,107	$29,130,745	$11,194,318	$3,657,550	$102,545	$460,336
		Rate Base Input equals Output							
	Equity Component of Rate Base	$63,828,238	$36,069,197	$9,940,843	$11,652,298	$4,477,727	$1,463,020	$41,018	$184,135
	Net Income on Allocated Assets	$5,974,323	$3,311,160	$1,966,615	$284,743	$509,896	($127,908)	$2,106	$27,711
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$5,974,323	$3,311,160	$1,966,615	$284,743	$509,896	($127,908)	$2,106	$27,711
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	99.50%	117.81%	87.42%	104.95%	64.87%	90.91%	110.95%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($7,442,333)	($4,599,965)	($306,628)	($1,805,601)	($354,291)	($360,502)	($5,583)	($9,764)
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($118,209)	$1,040,393	($774,537)	$114,924	($270,799)	($1,926)	$10,154
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	9.18%	19.78%	2.44%	11.39%	-8.74%	5.14%	15.05%

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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	5	7	8	9
	Residential	**GS <50**	**GS >50**	**Intermediate**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$4.13	$5.28	$3.85	$135.84	$0.00	-$0.02	-$0.03
Customer Unit Cost per month - Directly Related	$5.93	$7.28	$8.09	$167.43	$0.00	-$0.02	-$0.02
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.81	$25.24	$55.95	$244.04	$3.97	$15.56	$11.13
Existing Approved Fixed Charge	$27.88	$32.21	$277.81	$3,283.57	$1.39	$8.96	$9.66