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TABLES

EXHIBIT 7 - COST ALLOCATION INTERROGATORIES

OEB STAFF

7-STAFF-57

Weighting Factors

Ref 1: Exhibit 7, Pages 5-7

Preamble:

Explanations are provided to support the relative the ranking in costs between rate classes but are not at a level of detail sufficient to determine the appropriate weightings.

Question(s):

a) If available, please provide a derivation of the weightings used.

b) If not available, please explain how the specific weighting factors were arrived at.

SNC Response

a) Please see Tables 7-1 through 7-4 below.

TABLE 7-1: DERIVATION OF BILLING AND COLLECTING WEIGHTING FACTORS (ORIGINAL)

Customers, 2024 Forecast					
Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL
50,974	5,498	476	15	4	

BILLING AND COLLECTING:														
									Allocated Cost					
	2024 Budget	Relative Cost (weight) Per Customer					Total Weighted Customers	Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL
Olameter Inc.	40,000	2.0	2.0	1.0	1.0	-	113,436	0.71	0.71	0.35	0.35	-	-
					-	-	-	-	-	-	-	-	-
				-			-	-	-	-	-	-	-
							-	-	-	-	-	-	-
Kinetic	25,524	1.0	1.0	5.0	5.0	1.0	58,930	0.43	0.43	2.17	2.17	0.43	-
							-	-	-	-	-	-	-
5315 - Labour Billing Costs	377,546	1.0	1.0	2.5	2.0	1.0	57,696	6.54	6.54	16.36	13.09	6.54	-
5320 - Collecting	392,770	1.0	1.0	1.0	1.0	1.0	56,967	6.89	6.89	6.89	6.89	6.89	-
5315 - Remaining Billing Costs	1,137,774.0					-	-	-	-	-	-	-	-
Totals	**1,973,614**						**Identified Cost per Customer**	**14.58**	**14.58**	**25.77**	**22.50**	**13.87**	**-**
WEIGHTING FACTORS for Cost Allocation Model								**1.00**	**1.00**	**1.77**	**1.54**	**0.95**	**0.00**

TABLE 7-2: DERIVATION OF BILLING AND COLLECTING WEIGHTING FACTORS (REVISED)

Customers, 2024 Forecast					
Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL
50,974	5,498	476	15	4	43

BILLING AND COLLECTING:		Relative Cost (weight) Per Customer							Allocated Cost					
	2024 Budget	Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL	Total Weighted Customers	Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL
Olameter Inc.	40,000	2.0	2.0	1.0	1.0	-	-	113,436	0.71	0.71	0.35	0.35	-	-
					-	-		-	-	-	-	-	-	-
				-				-	-	-	-	-	-	-
								-	-	-	-	-	-	-
Kinetic	25,524	1.0	1.0	5.0	5.0	1.0	1.0	58,930	0.43	0.43	2.17	2.17	0.43	0.43
								-	-	-	-	-	-	-
5315 - Labour Billing Costs	377,546	1.0	1.0	2.5	2.0	1.0	1.0	57,696	6.54	6.54	16.36	13.09	6.54	6.54
5320 - Collecting	392,770	1.0	1.0	1.0	1.0	1.0	1.0	56,967	6.89	6.89	6.89	6.89	6.89	6.89
5315 - Remaining Billing Costs	1,137,774.0					-		-	-	-	-	-	-	-
Totals	**1,973,614**							**Identified Cost per Customer**	**14.58**	**14.58**	**25.77**	**22.50**	**13.87**	**13.87**
WEIGHTING FACTORS for Cost Allocation Model									**1.00**	**1.00**	**1.77**	**1.54**	**0.95**	**0.95**

SNC has adjusted their Cost Allocation Model for updated weighting factors for Billing and Collecting for the Unmetered Scattered Load Class. As USL customers are billed separately for unmetered scattered load, they have received the same weighting factors as SNC's street lighting customers. Please see the revised Cost Allocation Model attached as Excel file SNC_2024_Cost_Allocation_Model_20231110.

TABLE 7-3: DERIVATION OF METER READING WEIGHTING FACTORS

Customers, 2024 Forecast					
Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL
50,974	5,498	476	15	4	43

METER READING:		Relative Cost (weight) Per Customer						Total Weighted Customers	Allocated Cost					
	Costs	Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL		Res	GS<50	GS 50 - 999	GS 1,000-4,999	Strt Lgt	USL
ODS	106,000	1.0	1.0	1.0		-	-	56,948	1.86	1.86	1.86	-	-	-
ITRON	4,663				1.0	-	-	15	-	-	-	310.86	-	-
HoneyWell	51,780	1.0	1.0	1.0				56,948	0.91	0.91	0.91	-	-	-
								-	-	-	-	-	-	-
								-	-	-	-	-	-	-
								-	-	-	-	-	-	-
Remaining Metering Costs (001-2015)	89,333	1.0	1.0	1.0	1.0	-	-	56,963	1.57	1.57	1.57	1.57	-	-
								-	-	-	-	-	-	-
						-		-	-	-	-	-	-	-
Totals	**251,776**							**Identified Cost per Customer**	**4.34**	**4.34**	**4.34**	**312.43**	**-**	**-**
WEIGHTING FACTORS for Cost Allocation Model									**1.00**	**1.00**	**1.00**	**72.01**	**0.00**	**0.00**

TABLE 7-4: DERIVATION OF SERVICES WEIGHTING FACTORS

Services Weighting Factor

2022	Residential	Commercial
Over 200A	$ -	$21,266.06
Under 200A	$ 2,744.67	$ 1,188.41

2021	Residential	Commercial
Over 200A	$ -	$23,939.47
Under 200A	$ 2,935.36	$ 6,288.96

2020	Residential	Commercial
Over 200A	$ -	$14,943.25
Under 200A	$ 1,985.58	$ 3,725.91

2019	Residential	Commercial
Over 200A	$ -	$26,649.20
Under 200A	$ 3,059.80	$ 5,235.40

	Residential	GS<50	GS>50
	1.0	0.4	7.7
	1.0	2.1	8.2
	1.0	1.9	7.5
	1.0	1.7	8.7
Average	1.0	1.9	8.0

Note: GS <50 Under 200A average for 2022 was removed from the average as the under 200A commercial customer average value was derived from 10 data points, whereas the previous 3 years of data included over 30 data points thus, the data was not considered statistically representative and removed from the weighting factor.

b) N/A

7-STAFF-58

Load Profiles

Ref 1: Exhibit 7, Pages 8-13

Ref 2: Load Profile Derivation Model, sheet Hourly Data

Preamble:

Synergy North provides an explanation of how the weather normalization is performed for each class and provides an example of Thunder Bay Residential rate class.

Question(s):

a) Please confirm which weather station(s) are used for column R, "MeanTemp" – if this is derived from multiple weather stations, please provide an example derivation indicating how the weather stations are weighted.

b) Please confirm that the Kenora rate classes are normalized using the same "MeanTemp" values as ThunderBay.

c) If part b) cannot be confirmed,

   i. Please explain the approach taken
   ii. Please explain whether each day receives the same ranking in Thunder Bay and Kenora
   iii. Please explain how this approach avoids smoothing the typical peaks of Thunder Bay and Kenora when the profiles for the two rate zones are combined.

SNC Response

a) MeanTemp values are from the Thunder Bay A (airport) weather station.
b) Confirmed.
c) N/A.

7-STAFF-59

Load Profiles

Ref 1: Exhibit 7, Pages 8-13

Preamble:

Synergy North has provided a cost allocation model which reflects a harmonization of Thunder Bay and Kenora rate zones, and at the same time reflects load profile data updated for the first time since 2004.

Question(s):

a) As a scenario, please provide the demand allocators and resulting cost allocation model that would result from using the load profiles from Thunder Bay and Kenora's most recent rebasing applications**,** with each hour scaled so that the total is consistent with the 2024 load forecast.

SNC Response

a) SNC's hourly load profiles from Thunder Bay and Kenora's most recent rebasing applications are scaled to the 2024 load forecast in "SNC_7-Staff-59 Att. 1 (Updated 2004 load profiles))". The cost allocation model for this alternate scenario is provided as Excel file "SNC_7-Staff-59 Att.2 (CA Model with old profiles)".

TABLE 7-5: LOAD PROFILES

Rate Class	Scenario (Last COS demand data)	Original (filed CA model)
Residential	100.03%	99.50%
GS < 50	112.09%	117.81%
GS > 50	87.94%	87.42%
Intermediate	111.69%	104.95%
Street Light	64.61%	64.87%
Sentinel	90.85%	90.91%
USL	109.43%	110.95%

7-STAFF-60

Revenue-to-Cost

Ref 1: Cost Allocation Model, sheet I6.2 Customer Data

Ref 1: EB-2016-0105 Cost Allocation Model, sheet I6.2 Customer Data

Preamble:

In Thunder Bay's 2017 Cost Allocation model, the street lighting rate class indicated 13,274 devices with 2,361 connections. The current Synergy North Cost Allocation model indicates 13,656 devices on 13,656 connections.

Question(s):

a) Are there any areas in Synergy North's service territory where multiple streetlights share connections to the distribution system.

b) Please explain the reason for the change from several devices per connection in 2017 to one device per connection in 2024.

SNC Response:

a) Kenora has one billing account with 428 connections billed each month. Thunder Bay has three billing accounts with 13,322 connections billed each month.

b) The current device count provided as part of the SNC cost allocation model was derived from the latest street lighting dataset from the City of Thunder Bay and the City of Kenora and has been verified for accuracy. Unfortunately, the staff that provided the data for Thunder Bay's model in 2017 has left the corporation and did not leave any documentation for how it was calculated.

7-STAFF-61

Revenue-to-Cost

Ref 1: Exhibit 7, Page 15

Preamble:

The revenue-to-cost ratio for Street Lighting is proposed to be moved from 64.9% to 69.6% in 2024 as part of a two-year transition to 80% revenue-to-cost. The revenue-to-cost ratio for Sentinel Lighting is proposed to be moved from 90.9% to 90.5% - away from unity. Both are proposed to mitigate bill impacts under 10% for customers currently in the Thunder Bay rate zone.

Question(s):

a) Have other options been considered for mitigating the impact to Sentinel Lighting customers other than a move away from unity.

SNC Response

a) SNC considered changing the disposition period of rate riders; however, the overall bill impact is negative, and riders are disposed of over one year, so extending the disposition period would not reduce bill impacts. Distribution rates were reduced to the 90.5% revenue-to-cost ratio because this was the only component of total customer bills in which SNC can reduce to limit rate increases to the 10% ceiling. The difference in revenue between 90.9% and 90.5% revenue-to-cost ratios for the Sentinel Lighting rate class is $78 so a rate mitigation deferral account was not considered.

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

7.0-VECC-56

Reference: Cost Allocation Model, Tab I4 BO Assets

Exhibit 7, page 8

Preamble: The Application states:

"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".

a) In Tab I4, USOA #1805 is all sub-categorized as "Land – Stations <50 kV". What is the land actually used for?

b) What Buildings are included in USOA #1808 (per Tab I4)?

c) In Tab I4, for USOA #1815 through #1860, can the value of these assets be broken down by rate zone (i.e., Thunder Bay vs. Kenora)?

d) In Tab I4, for USOA #1815 through #1860 how were the break-out percentages shown in Tab I4, column D determined?

SNC Response:

a) This is the land on which the station and all the stations' associated auxiliary equipment (such as breakers, protective devices, DC supply components, metering, etc.) are located.
b) The buildings that are included in USoA account 1808 are Synergy North's Operations Centre and Fleet Garage, located at 37 Front St in Thunder Bay.
c) The following are the assets broken down by rate zone; however, the only available asset data compiled for Kenora is at December 31, 2022. The exercise to break out assets is done at year-end as part of requirements in the MAAD application to calculate IFRS Capital difference tracking

between Kenora and Thunder Bay. For the purposes of this IR response, SNC has assumed the difference between Kenora Rate Zone assets at December 31, 2022, and the total USoA account is allocated to Thunder Bay.

TABLE 7-6: ESTIMATED VALUE OF ASSETS BROKEN DOWN BY RATE ZONE

USOA	Account Description	Thunder Bay	Kenora as at December 31, 2022
1815	Transformer Station Equipment	$1,272,321	2,919,612
1820	Distribution Station Equipment	$ 8,176,760	326,785
1830	Poles, Towers and Fixtures	$80,013,195	4,646,726
1835	Overhead Conductors and Devices	$59,877,218	1,554,838
1840	Underground Conduit	$18,879,357	1,191,237
1845	Underground Conductors and Devices	$27,301,042	452,517
1850	Line Transformers	$43,111,244	1,809,257
1855	Services	$24,027,637	562,183
1860	Meters	$12,439,847	$960,925

Breakout % determination:

- UsoA 1815 – No breakout % applied.

d) UsoA 1820 was broken out by the split between Distribution Station Equipment – Primary Below 50kV asset value and Wholesale meter asset value.

- UsoA 1830 was broken out by the number of primary vs. secondary poles.
- USoA 1835, USoA 1840, and USoA 1845 are broken out by the length of kilometres of primary and secondary conductors or conduits in each asset account.
- UsoA 1850 and 1860 - no breakout % applied.

7.0-VECC-57

Reference: Exhibit 7, page 6

Preamble: The Application states:

"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."

a) Does SNC have any costs for Services types assets for these classes recorded in other USoAs? If so, in what accounts are the costs recorded?

SNC Response:

a) No, SNC does not have any costs included in any of its USoAs for Street Lighting, Sentinel Lighting, and Unmetered Scattered Load.

7.0-VECC-58

Reference: Exhibit 7, page 6

Preamble: The Application states:

"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."

a) Please provide a copy of the analysis undertaken to derive the proposed Billing and Collecting weights.

b) Please explain why there are no weightings associated with the Sentinel and USL classes.

SNC Response:

a) Please see the response to 7-STAFF-57.
b) No weightings are assigned to the Sentinel-class as the customers in the Sentinel-class are also customers in other rate classes, so there are no incremental billing and collecting costs. Please see the response to 7-STAFF-57 for revised weighting factors associated with the USL class.

7.0-VECC-59

Reference: Exhibit 7, page 7

Cost Allocation Model, Tab I7.1, Meter Capital

Preamble: The Application states:

"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."

a) Are SNC's installation costs per meter (including time requirements per meter) the same in both rate zones? If not, what are the differences and how was the cost per meter derived for each meter type as set out in Tab I7.1?

SNC Response:

a) The meters and their installation costs are the same in both rate zones.

7.0-VECC-60

Reference: Exhibit 7, pages 7-8

Cost Allocation Model, Tab I7.2, Meter Reading

Preamble: The Application states:

"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."

a) Please provide a copy of the analysis undertaken to derive the proposed meter reading weights.

b) Are SNC's meter reading costs per meter (including time requirements per meter) the same in both rate zones? If not, what are the differences and how was this reflected in the analysis of the cost for meter reading undertaken to derive the meter reading weights?

SNC Response:

a) Please see 7-Staff-57.

b) Yes, meter reading costs are the same in both rate zones.

7.0-VECC-61

Reference: Cost Allocation Model, Tab E1 Categorization

a) Tab E1 reports a total customer count of 57,369 and 1,270 for the total kM of lines which results in a density of 45. Please provide the comparable values for each of the Thunder Bay and Kenora rate zones.

SNC response:

a) Please see the table below. Note that both rate zones have a density between 30 and 60, so they would both be medium-density for the purposes of classifying costs between demand and customer-related in the cost allocation model.

TABLE 7-7: CUSTOMER DENSITY BY CIRCUIT-KILOMETERS

	Thunder Bay	Kenora	SNC Total
Total Customers	51,739	5,630	57,639
Total Circuit-Kilometers of lines	1,171	99	1,270
Density	44	57	45

7.0-VECC-62

Reference: Exhibit 7, pages 9

Exhibit 3, page 36

Preamble: The Application states:

"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)." (page 9)

The Application also states that weather normalized load profiles were developed for the Residential, General Service < 50 kW, General Service 50 to 999 kW, and General Service 1,000 to 4,999 kW classes. (pages 12-13)

a) Please explain why the load profile for the GS 1000-4999 class was weather normalized when for purposes of the load forecast the class' load was determined to not be weather sensitive.

b) Did SNC develop the weather normalized load profiles for 2024 by: i) weather normalizing just the 2022 load profiles and then adjusting the results to match the forecast 2024 kWh for each class or ii) by weather normalizing the load profiles for each of the years 2019, 2021 and 2022 (as suggested by the reference), adjusting the results from each to match the forecast kWh for each class and the averaging the results?

    i. If only the 2022 load profiles for each customer class were "weather normalized", please explain why the weather normalization methodology was not also applied to the 2019 and 2021 loads for each class and the proposed 2024 load profile for each class based on an average of the three years.

    ii. If only the 2022 load profiles for each customer class were "weather normalized", please provide the results (i.e., the 2024 CP and NCP values) for each customer class based on: i) adjusted 2019 data and ii) adjusted 2021 data.

SNC Response:

a) The weather statistics used in the load forecast were not found to be statistically significant on a monthly basis, but the heating load (HDD) was found statistically significant on weekdays when using hourly data in the load profile derivation.

b) Weather normalized load profiles were derived for each year, and the 2024 profiles were derived by i) adjusting the 2022 results to the 2024 kWh forecast for each class.

The 2022 year is used because it is the most recent year and did not have significant direct COVID impacts but includes the ongoing impacts triggered by COVID of people working from home. The 2019 data does not reflect load impacts of people working more from home or possible load

changes of General Service classes following reclassifications in the last few years. The 2021 data includes some direct COVID impacts as there were still stay-at-home mandates over this period.

Please see Table 7-8 and 7-9 below.

i)

TABLE 7-8: ADJUSTED 2019

	Residential	GSlt50	GS50to999	Intermediate	Streetlight	Sentinel Light	USL
1CP	79,443	27,746	46,111	21,578	1,244	22	234
4CP	292,803	104,092	167,094	65,398	2,840	47	965
12CP	728,683	313,514	496,391	251,389	5,279	91	2,863
1NCP	87,162	33,984	51,278	31,466	1,371	23	262
4NCP	326,096	130,085	196,861	123,956	5,486	94	1,007
12NCP	832,082	353,526	529,444	347,650	15,940	272	2,920

ii)

TABLE 7-9: ADJUSTED 2021

	Residential	GSlt50	GS50to999	Intermediate	Streetlight	Sentinel Light	USL
1CP	76,543	30,004	48,571	21,239	1,206	22	232
4CP	283,564	104,559	174,558	64,422	3,812	67	953
12CP	728,382	320,130	517,522	260,211	6,224	111	2,832
1NCP	81,378	32,662	50,597	30,416	1,303	22	257
4NCP	315,786	128,670	197,048	120,280	5,212	89	993
12NCP	822,671	352,731	542,201	340,656	15,636	266	2,887

7.0-VECC-63

Reference: Exhibit 7, pages 8-13

SNC's 2024 Load Profile Derivation Model

Preamble: The Application states (page 11):

"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."

a) In the Load Profile Derivation Model, Tab Res sets out the calculation of the hourly adjusted loads for the Residential class. Please clarify whether the Tab is based the loads and the HDD and CDD values for just Thunder Bay or for all of SNC.

b) If all of SNC, what is the basis for the HDD and CDD values?

c) In the Load Profile Derivation Model (Tab 2024 Profile (K)) all of the hourly customer class load values (Columns E-G) are hard coded and not based on formulae as is the case for similar Thunder Bay customer classes (Tab 2024 Profile (TB)). Please explain how the Kenora values were derived.

d) Please confirm that the CP and NCP values for each SNC rate class are calculated by adding the weather normalized 2024 Kenora and Thunder Bay hourly loads and then calculating the CP and NCP values based on the totals for each hour.

e) If not confirmed, how were the CP and NCP values for each SNC customer class determined?

f) If confirmed, given that the Thunder Bay and Kenora rate zones are non-contiguous, have different weather conditions and the facility needs in each zone will be driven by each zone's loads, please explain why it would not be more appropriate to separately determine the CP and NCP values for each rate zone and add these values for purpose of the cost allocation model.

g) Please provide the 2024 weather normalized CP and NCP values by customer class for each of the Kenora and Thunder Bay rate zones.

SNC Response:

a) This tab includes data only for Thunder Bay.

b) N/A.

c) The class tabs in the filed model are Thunder Bay loads to demonstrate the load profile derivation methodology. Kenora loads are calculated in a separate version of the model that follows the same methodology.

d) Confirmed.

e) N/A.

f) Elenchus considered two options for calculating the demand data used in the cost allocation model: (i) the proposed methodology of using CP/NCP figures from a single LDC-wide load profile and (ii) calculating separate CP/NCP figures for each rate zone and combining CP/NCP figures as described in the interrogatory. Elenchus reviewed the load profile methodologies used by Veridian Connections and Hydro One Distribution. Veridian Connections merged its load profiles for the purposes of calculating CP/NCP figures Elenchus's understanding of the Hydro One Distribution methodology, based on its explanation of how it incorporated seasonal customers within other rate classes and incorporated acquired utilities, is that Hydro One calculates a single load profile for the purposes of calculating CP/NCP figures. The proposed methodology was selected because it is consistent with these precedents.

g) Separate CP/NCP values by class for each rate zone are provided below. This information is included in the Load Profile Derivation model tabs '2024 Profile (TB)' (N15:U17 and N34:U36) and '2024 Profile (KN)' (L15:Q17 and L34:Q36).

TABLE 7-10: 2024 WEATHER NORMALIZED CP AND NCP, THUNDER BAY

Thunder Bay							
	Residential	**GSlt50**	**GS50to999**	**Intermediate**	**Streetlight**	**Sentinel Light**	**USL**
1CP	69,719	24,542	39,679	21,812	1,232	23	215
4CP	224,355	95,395	148,718	88,701	1,232	23	885
12CP	646,006	272,353	431,603	279,877	3,695	68	2,632
1NCP	75,092	27,182	41,831	30,187	1,232	23	239
4NCP	287,846	106,467	163,528	119,774	4,926	91	921
12NCP	756,765	294,581	448,617	338,131	14,778	272	2,684

TABLE 7-11: 2024 WEATHER NORMALIZED CP AND NCP, KENORA

Kenora					
	Residential	**GSlt50**	**GS50to4999**	**Streetlight**	**USL**
1CP	9,813	3,843	5,510	97	20
4CP	32,768	16,038	21,970	291	79
12CP	85,912	48,486	64,344	388	231
1NCP	9,813	5,899	6,357	97	22
4NCP	35,691	22,578	24,901	388	83
12NCP	90,325	57,055	68,790	1,164	236

7.0-VECC-64

Reference: Exhibit 7, pages 11-12

SNC's 2024 Load Profile Derivation Model, RES, GS<50,

GS>50 and INT Tabs

Preamble: The Application states:

"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."

a) Please confirm that by using binary variables to account for the impact of weekends and holidays as opposed to weekdays on load the model implicitly assumes that the impact of a change in HDD or CDD value is the same on weekends and holidays as it is on weekdays. If confirmed, please explain why this "assumption" is reasonable? If not confirmed, please explain why not.

b) COVID flag variables were included for 2021 and 2022 in many of the load forecast models set out in Exhibit 3. However, no explanatory variables were included in the regression models used for

purposes of weather normalization even though the years used included 2021 and 2022. Please explain why.

SNC Response:

a) Binary variables are not used to account for the impact of weekends and holidays relative to weekdays. As noted in the preamble, "…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." The models include separate weekday HDD/CDD variables and weekend/holiday HDD/CDD variables. For example, in the 'Res' tab, the statistical output shows the impact of each CDD in the noon hour on weekdays ("WDCDD1612" cell C41) is 713 kW and the impact of each CDD in the noon hour on weekends ("WEHCDD1612" cell C89) is 1,520 kW.

b) COVID flag variables would be equivalent in each hour of the year, so they would not meaningfully impact weather normalization. Hourly loads are scaled to total forecast consumption by class, which includes COVID variables.

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Reference: Exhibit 7, page 15

Exhibit 8, pages 21-22

RRWF, Cost Allocation Tab

Preamble: SNC's proposals regarding the revenue to cost ratio are set out in the RRWF as follows:

Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
	Test Year	Price Cap IR Period		
	2024	2025	2026	
Residential	99.50%	99.50%	99.50%	85 - 115
GS < 50	115.82%	114.44%	114.44%	80 - 120
GS > 50	88.72%	88.72%	88.72%	80 - 120
Intermediate	104.95%	104.95%	104.95%	80 - 120
Street Light	69.59%	80.00%	80.00%	80 - 120
Sentinel Light	90.54%	90.54%	90.54%	80 - 120
USL	110.95%	110.95%	110.95%	80 - 120

a) Given that the proposal to decrease the Sentinel Lighting's Revenue to Cost ratio from 90.9% to 90.5% is based on keeping the class' total bill impact at less than 10%, why would it not be appropriate to increase the ratio to 90.9% in 2025 as opposed to maintaining the value at 90.5%?

SNC Response:

a) The Sentinel Light class is a small portion of revenue, and the difference between 90.5% and 90.9% is less than $100. The incremental revenue from moving the Sentinel Light class to 90.9% would not impact the rates of the GS<50 kW class at the 4th decimal point, so the only impact of this change in 2025 is a slight increase in Sentinel Light rates and revenues. No rebalancing is proposed because the rate and revenue impact is outweighed by the administrative cost of rebalancing rates.