Wellington North Power Inc.'s (Applicant) Responses to

Vulnerable Energy Consumers Coalition (VECC)

Pre-Settlement Conference Clarification Questions.

2021 Electricity Distribution Rates Application

EB-2020-0061

February 25, 2021

Contents

VECC-62

REFERENCE: 3-VECC 19
Load Forecast Model, Tab 3a (Rate Class Energy Model)
Exhibit 3, page 28, Table 17

PREAMBLE: The response to VECC 19 states that "the values in Table 17 of Exhibit 3 (page 28) illustrates the Sensitive Customers Billed kWh with Losses for the months of January 2010 to December 2019."

a) The values in Table 17 do not reconcile with the GS 1,000-4,999 kW customer usage as reported in the Rate Class Energy Model and the referenced loss factors (For example, for 2019 Table 17 shows usage of 50,547,692 while the Rate Class Energy Model shows a metered usage of 42,766,148 kWh. This suggests a loss factor of 1.182, well in excess of the 1.0656 quoted in the response to VECC 19). Please reconcile and explain whether the Sensitive Customer monthly usage values used in the Load Forecast regression model need to be revised.

Wellington North Power Inc.'s (WNP) Response:

a) Table 17 showed the monthly billed kWh with Losses for the months of January 2010 to December 2019 for the Sensitive Customers. The "Sensitive Customers" consists of 6 accounts of which:
   - All five (5) accounts from rate class GS 1,000-4,999 kW.
   - One (1) account from rate class GS 50-999 kW. This account was in rate class GS 1,000-4999 kW until November 2014 when, following a review of monthly kW demand, the account was re-classified to GS 50-999 kW rate class.

   Therefore, the "Sensitive Customers" variable comprise 5 accounts in rate class GS 1,000-4,999 kW plus 1 account from GS 50-999 kW.

   Furthermore, in the Load Forecast worksheet 3a Rate Class Energy Model, the values shown in cells N3 to N12 are solely for accounts in rate class GS 1,000-4,999 kW and are metered kWh, i.e. without loss.

   In responding to this question, WNP has provided an excel file named "2-VECC-62 Sensitive Customers vs GS1000-4999 kW" which includes the following:

- Worksheet "Table 17 Sensitive Billed kWh" shows the metered kWh usage (no Loss) and billed kWh (with Loss) for Sensitive Customer accounts. This worksheet includes notes about account re-classifications that occurred during the period 2010 to 2019.
  "The Total Billed Usage (kWh)" (column E) reconciles to the data shown in Table 17 and as per the "Sensitive Customer" variable data used in the Load Forecast.

- Worksheet "Rate Class GS 1000-4999 kW" shows the metered kWh usage (no Loss) and billed kWh (with Loss) for GS 1,000-4,999 accounts for the period 2010 to 2019.
  The data in "GS 1,000- 4,999 kW Metered kWh cells B125 to B134 reconciles to Load Forecast worksheet 3a Rate Class Energy Model values in cells N3 to N12.

  Note: For privacy reasons, WNP has not named the customers or included the account numbers.

Based upon the information provided above and the supporting excel file, WNP believes that the Sensitive Customer monthly usage values used in the Load Forecast regression model do not need to be revised.

VECC-63

REFERENCE: 3-VECC 26 c) & d)

a) The response to VECC 26 d) makes reference to a file "3-VECC-26d IESO Results 2011-2014". There is no file with this name on the Board's web-site. However, there two files (one excel and one pdf) labelled VECC 26 c). Please confirm that the excel file should have been labelled "3-VECC-26d IESO Results 2011-2014".

WNP's Response:

WNP confirms the Applicant submitted an excel file labeled "3-VECC-26**d** IESO Results 2011-2014" on the OEB's web-portal as per the utility's response to VECC's IR question 3-VECC-26 part d). Included with this response is a copy of the automated e-mail from the OEB Registrar titled *"Confirmation of Application Submission for Wellington North Power Inc., Case Number EB-2020-0061"* (dated February 8th 2021 at 4:18 pm) which lists the files uploaded to the OEB's web-portal. In this e-mail, the 12th file loaded is labeled "3-VECC-26**d** IESO Results 2011-2014.xlsx". A copy of this email has been included as an attachment – please see "2-VECC-63 Confirmation of Application Submission".

Upon reviewing the OEB's web-portal, WNP can see the excel file has been incorrectly labeled as ""3-VECC-26**c** IESO Results 2011-2014".

Regardless, WNP confirms the excel file on the OEB's web-portal should have been labelled as "3-VECC-26**d** IESO Results 2011-2014".

VECC-64

REFERENCE: 3-VECC-26 i), j) & k)
Staff 47 a)
VECC 23 c)
WNP 2017 Final Annual Verified CDM Program Results
WNP Participation and Cost (P&C) Report, April 2019

a) The persisting savings from 2017 CDM programs as set out in VECC 26 k) {Excel File – Tab C} for the year 2020 (873,158 kWh) don't match the savings value provided in the IESO 2019 P&C Report (965,450 kWh). Please reconcile and indicate whether the 2017 CDM savings used in the Load Forecast model need to be revised.

b) The persisting savings from 2018 CDM programs as set out in VECC 26 k) {Excel File – Tab C} for the year (646,847 kWh) don't match the savings value provided in the IESO 2019 P&C Report (632,802 kWh). Please reconcile and indicate whether the 2018 CDM savings used in the Load Forecast model need to be revised.

c) According to VECC 26 i) the annualized 2019 savings from 2019 programs was calculated by multiply the results for the first 3 months as reported in the 2019 P&C Report of 39,749 kWh by 4 and then adding one month of Street Light CDM savings (34,115 kWh) for a total of 193,111kWh. Please explain why only one month of Street Light savings was added when according to Staff 47 all of the Street Light conversion was completed by the end of December 2019.

d) According to the notes included in the VECC 26 k) Excel File (Tab C) the 2020 and 2021 savings from 2019 CDM programs used for the CDM variable in the Load Forecast include 12 months of savings from the Street Light LED conversion program. However, VECC 23 c) claims that the CDM variable does not include the Street Light CDM savings, hence the need for the purchase power adjustment described on page 39 of Exhibit 3. Please reconcile and explain whether the Street Light CDM adjustment is really required.

WNP's Response:

a) WNP has corrected the model to show persisting savings from 2017 CDM programs to be 965,450 kWh for years 2020 and 2021. This kWh savings was taken from the IESO's April 2019 P&C report worksheet "LDC Progress" cell BC105 – "2017 Year to Date" total.

WNP advises that because of this change, the CDM variable data in the Load Forecast model

needs to be revised.

b) From the IESO's April 2019 P&C report worksheet "LDC Progress" WNP used the amount in cell BD105 of 646,847 kWh for the "2018 Year to Date" total for years to record:
   - 2018 CDM program year results; and
   - 2018 CDM program persistence for years 2019, 2020 and 2021.

   VECC's reference to 632,802 kWh is from cell CH105 of the same worksheet of the report; however using this value would mean that, for consistency, WNP should then use the "2017 Year to Date" as reported in cell CG105 of 855,141 kWh which is different to the value stated in response a) to this question.

   For consistency, WNP recommends using the same sections of the IESO's April 2019 P&C report worksheet "LDC Progress" to report both 2017 and 2018 Year to Date savings and persistence savings of 965,450 kWh and 646,847 kWh respectively (cells BC105 and BD105).

c) WNP started replacing the HPS bulbs with LED streetlights in August 2019 and completed all the bulb replacements in December 2019. Given that WNP's Load Forecast is based on a Wholesale Purchases rather than rate-class specific, the "full" effect of energy savings as a result of all streetlight bulbs being replaced would be represented in the Wholesale Purchases from January 2020 onwards.

   WNP acknowledges that, for CDM program results achieved prior to the Bridge or Test Years, LDCs can apply a weighting factor for inclusion in the CDM kWh adjustment to their Load Forecast. Typically this adjustment is half-year (0.5) of reported CDM savings as persistence e.g. only 50% of 2019 CDM programs are assumed to impact the 2020 load forecast based on the "half-year" rule[1].

   Proposal:
   Given that the replacement of HPS to LED bulbs started in August 2019 and was completed in December 2019, WNP proposes the following for the CDM variable data in the Load Forecast:
   1. For 2019 CDM Program year results, instead of the half-year rule, a 25% (0.25) adjustment is made.
   2. For 2019 CDM Program year persistence in year 2020, a 75% adjustment is applied.

[1] 2021 Filing Requirements Chapter 2 Appendices work form, worksheet App_2-I LF_CDM.

3. For 2019 CDM Program year persistence in year 2021, no (0%) adjustment is applied.

Assuming this proposal is accepted by all parties, then the CDM adjustment for 2019 CDM programs savings would be:

Source	**kWh Savings**	**Adjustment to 2019 Load Forecast**
IESO's April 2019 P&C report January 2019 to March 2019	=(39,749 kWh *4) Annualized – 158,996 kWh	*158,996 x 0.5 (half-year)* = 79,498 kWh
Streetlight LED Conversion Worksheet 8. LRAMVA model	Annualized savings of 409,381 kWh	*409,381 x 0.25* = 102,345
Total Adjustment for 2019 CDM Program in 2019		= 181,843 kWh

Persistence	**Adjustment to 2019 Load Forecast**
Persistence for 2019 CDM Program in 2020	158,996 + (Streetlight savings 409,381 x 0.75) = 466,032 kWh
Persistence for 2019 CDM Program in 2021	158,996 + 409,381 (Streetlight savings with no adjust) = 568,377 kWh

To supplement its' response, WNP has included an excel file showing the CDM adjustment variable data based upon the above proposal that could be used in the Applicant's Load Forecast – please refer to excel file "2-VECC-64 WNP 2006-2019 CDM kWh Savings Summary Pre-Settlement", in particular worksheets:

- "C. 2015-2020 Programs".
- "D. CDM ½ yr Rule".
- "F. Input Variable – Load F'cast".

WNP would be willing to discuss this proposal at the Settlement Conference.

d) Regarding VECC's question *"Please reconcile and explain whether the Street Light CDM adjustment is really required"*, the LDC would be agreeable to remove the Streetlight CDM adjustment subject to all parties agreeing to WNP's proposal as discussed in response to part c) above.

VECC-65

REFERENCE: 3-VECC-47 c)

PREAMBLE: The response explains the lower Services weighting for GS<50 as follows:

> "The weighting for GS<50 kW is less than Residential because there are so many fewer customers (less than one seventh). To make the weighting equal would assume that there is over a 700% increase in the cost of providing service to GS<50 kW versus a Residential customer. A weighting of 0.4 means there is a much more accurate estimate of just under 300% increase in cost for the average GS<50 kW service over residential customer."

a) Please confirm that, in the Cost Allocation model, the Services Weightings are expressed on a per customer basis and then in Tab I6.2 multiplied by the number of customers in the class to derive the overall weighting for Services by customer class.

b) Based on this confirmation and the response provided above shouldn't the Services weighting for GS<50 be 3.0?

WNP's Response:

a) WNP's understanding of the OEB's Cost Allocation model is:
   - In worksheet "I5.2 Weighting Factors" the Services Weightings are expressed as per customer basis.
   - In worksheet "I6.2 Customer Data" row 47 "Weighted –Services" multiplies the Service Weighting factor by the number of customers in the rate class to determine the overall weighting for Services by each customer class.

b) WNP agrees with VECC's comment – the Weighting Factor for Services for GS<50 kW rate class should be 3.0.

By changing the GS<50 kW Services Weighting Factor in the OEB's Cost Allocation Model (CAM) from 0.4 to 3.0, the effect to the revenue-to-expenses ratios are:

Rate Class	**Revenue to Expenses** *CAM as filed with Interrogatories*	Revenue to Expenses CAM Updated
Residential	101.19%	102.90%
GS <50 kW	126.47%	118.50%

GS 50-999 kW	100.00%	100.00%
GS 1000-4999 kW	83.25%	83.25%
Streetlight	46.05%	46.05%
Sentinel	99.72%	99.72%
USL	179.42%	179.42%

Recommendation:
The above table demonstrates this change has implications to the Rate Design of the Residential and GS<50 kW rate classes. WNP recommends this change is accepted by all parties and, if agreed at the Settlement Conference, the updated Cost Allocation Model is to be filed on the OEB's web portal.

In replying to VECC's pre-settlement conference questions, WNP has provided an updated copy of the Cost Allocation Model that includes the change noted above for all parties to review. (File named 2021 Cost Allocation Model v1.0 EB-2020-0061 Pre-Settlement).

VECC-66

REFERENCE: 3-VECC 45
Cost Allocation Model, Tab I4 (BO Assets)

PREAMBLE: VECC 45 explains the derivation of the 75/25 split for underground cable as between primary and secondary.

a) Please explain why 100% of underground conduit is considered to be primary.

WNP's Response:

a) Historically WNP has not separated conduit asset expenses between primary and secondary. Prior to 2020, the balance in the 1840 account was $861. In 2020, WNP did install conduit for primary at a cost of $40,670 and hence the 100% of this expense was allocated to the primary in the Cost Allocation model.

VECC-67

REFERENCE: 7-Staff 70 a) & d)
Cost Allocation Model, Tabs I6.2 and I8

PREAMBLE: The response to Staff 70 a) states: "WNP wish to confirm that every customer relies on the LDC for secondary distribution."

The response to Staff 70 b) states that for the GS 50-999 class: "WNP confirms that the demand profiles at sheet I8 should have reflected 80% which supports the fact that 80% of demand is served by Wellington North Power and 20% is served by customer owned transformers. A revised Cost Allocation Model filed with these responses have been amended to reflect this change."

a) Please explain how the situation can arise where the customer owns the transformer (as is the case with all GS 1,000-4,999 customers and some GS 50-999 customers) but WNP owns the secondary assets on the low side of the transformer.

b) It is noted that the demand data in for the GS 50-999 class in Sheet I8 now has a Line Transformer 4NCP value equal to 80% of the Primary 4NCP value consistent with the response to Staff 70 b). However, it is also noted that for the GS 50-999 class: i) the Secondary 4NCP value is set at 80% which is inconsistent with the response to Staff 70 a) and ii) both the Line Transformer and Secondary customer counts in Sheet I6.2 are equal to the Primary customer count which is inconsistent with Sheet I8. Please reconcile.

WNP's Response:

a) WNP acknowledges that the confirmation made in its' response to 7-Staff-70 a) was incomplete and therefore incorrect. The statement should have said:

> "WNP wish to confirm that every customer relies on the LDC for secondary distribution except for those customers that do not own their own transformers. For customers that own their own transformers, they are connected to the primary distribution system".

To be clear, all customers in rate class GS 1,000-4,999 kW and 2 customers in rate class GS 50-999 kW own their own transformers and are connected to the primary distribution system; all other customers rely on the LDC for secondary distribution.

b) In the Cost Allocation Model, WNP has updated worksheet "I6.2 Customer Data" cell F25 to be 32 instead of 34. The value of 32 in cell F25 represents the number customers who rely the LDC for secondary distribution.

In replying to VECC's pre-settlement conference questions, WNP has provided an updated copy of the Cost Allocation Model that includes the change noted above for all parties to review. (File named 2021 Cost Allocation Model v1.0 EB-2020-0061 Pre-Settlement).

Recommendation:
Given that there is a material change as a result of the changes made in Cost Allocation Model in responding to VECC's pre-settlement question VECC-67, WNP recommends that, subject to agreement from all parties, a revised version of the Cost Allocation Model is filed on the OEB's web portal.

VECC-68

REFERENCE: 7-Staff 70 a) & d)
Cost Allocation Model, Tabs I6.2 and I8

PREAMBLE: The prelude to Staff 70 states: "All customers in the GS 1,000-4,999 kW rate class own their own transformers and therefore are not eligible for the transformer allowance."

The response to Staff 70 a) states: "WNP also confirms that all customers in the General Service 1,000-4,999 kW rate class own their transformation facilities and do not contribute to the system transformation costs. The volumetric rate billed to customers in this rate class exclude the transformation cost (voltage step-down) element because it is the customer's equipment and not the utility's equipment performing the transformation activity."

The response to Staff 70 d) states: "WNP has updated the model to populate the demand allocator of Line Transformer NCP for the GS 1000-4999 class to reflect the fact that all customers in this class do not receive a transformer allowance."

a) In Sheet I8 the Line Transformer and Secondary 4NCP values for the GS 1,000-4,999 class are equal to the Primary 4NCP value. Similarly, in Sheet I6.2 the Line Transformer and Secondary customer counts for the GS 1,000-4,999 class are equal to the Primary customer count. This would suggest that all GS 1,000-4,999 customers use WNP owned transformers which is inconsistent with the prelude to Staff 70. Inclusion of these 4NCP values for this class also means this customer class is allocated a share of line transformer costs which is inconsistent with Staff 70 a). Please reconcile.

WNP's Response:

a) In the Cost Allocation Model, WNP has updated the following worksheets:

- Worksheet "I6.2 Customer Data" for rate class GS 1,000-4,999 kW:
  - Entered zero (0) for Line Transformer and Secondary Customer Base (cells H24 and H25) because all customers in this rate class are connected to the primary distribution system and use their own transformers.
- Worksheet "I8 Demand Data" for rate class GS 1,000-4,999 kW:
  - Entered zero (0) for Line Transformer NCP and Secondary NCP in cells H57, H58, H63, H64, H69 and H70 because all customers in this rate class are connected to

the primary distribution system and use their own transformers.

Through making the changes to the OEB's Cost Allocation Model (CAM) as described above, as well as in response to questions VECC-65 and VECC-67, the effect to the revenue-to-expenses ratios are:

Rate Class	**Revenue to Expenses** *CAM as filed with Interrogatories*	Revenue to Expenses CAM Updated
Residential	101.19%	98.08%
GS <50 kW	126.47%	110.97%
GS 50-999 kW	100.00%	88.10%
GS 1000-4999 kW	83.25%	107.11%
Streetlight	46.05%	45.81%
Sentinel	99.72%	99.69%
USL	179.42%	175.20%

The table below shows the Bill Impact table as a consequence of the revisions made to data through responding to interrogatories as per page 5 of "Wellington North Power Applicant Response to IR EB-2020-0061" as filed on February 8th 2021:

	A		B		C		Total Bill	
	$	%	$	%	$	%	$	%
Residential	$ 1.33	3.50%	$ 2.97	6.33%	$ 3.24	5.70%	$ 2.62	2.07%
General Service <50kW	$ 2.19	2.58%	$ 6.57	6.13%	$ 7.31	5.60%	$ 5.90	1.84%
General Service 50-999kW	$ 57.03	8.42%	$ 146.07	18.09%	$ 164.91	11.74%	$ 156.61	1.91%
General Service 1000-4999kW	$ 2,489.27	31.49%	$ 4,229.56	43.66%	$4,485.60	25.32%	$ 4,585.30	3.60%
Unmetered Scattered Load	$ (10.35)	-15.92%	$ (9.24)	-13.62%	$ (9.14)	-12.90%	$ (7.43)	-8.69%
Sentinel Lighting	$ 35.65	10.88%	$ 56.29	16.93%	$ 56.85	16.24%	$ 46.16	15.50%
Street Lighting	$ 1,821.28	110.08%	$ 3,764.25	222.03%	$3,770.12	200.59%	$ 4,248.39	89.38%

Rate Riders are for 24 months disposition period.

The table below shows the Bill Impact table as a consequence of incorporating the changes to the OEB's Cost Allocation Model as discussed in responses to pre-settlement questions VECC-65, VECC-67 and VECC-68:

	A		B		C		Total Bill	
	$	%	$	%	$	%	$	%
Residential	$ 2.08	5.50%	$ 3.72	7.94%	$ 4.00	7.03%	$ 3.23	2.56%
General Service <50kW	$ 7.11	8.39%	$ 12.49	11.67%	$ 13.23	10.14%	$ 10.71	3.35%
General Service 50-999kW	$ 57.15	8.44%	$ 154.38	19.11%	$ 173.22	12.33%	$ 165.99	2.03%
General Service 1000-4999kW	$ 1,777.19	22.48%	$ 3,635.69	37.53%	$ 3,891.73	21.97%	$ 3,914.23	3.07%
Unmetered Scattered Load	$ (8.97)	-13.80%	$ (7.55)	-11.13%	$ (7.45)	-10.52%	$ (6.06)	-7.09%
Sentinel Lighting	$ 35.60	10.87%	$ 60.71	18.26%	$ 61.27	17.50%	$ 49.75	16.70%
Street Lighting	$ 1,841.97	111.33%	$ 3,826.70	225.72%	$ 3,832.57	203.91%	$ 4,318.96	90.86%

Rate Riders are for 24 months disposition period.

In replying to VECC's pre-settlement conference questions, WNP has provided an updated copy of the Cost Allocation Model that includes the change noted above for all parties to review. (File named 2021 Cost Allocation Model v1.0 EB-2020-0061 Pre-Settlement).

Recommendation:
Given that there is a material change as a consequence of the changes made in Cost Allocation Model in responding to VECC's pre-settlement questions VECC-65, VECC-67 and VECC-68, WNP recommends that, subject to agreement from all parties, a revised version of the Cost Allocation Model is filed on the OEB's web portal.

VECC-69

REFERENCE: VECC 55
RTSR Workform, Tabs 3 and 5

PREAMBLE: VECC 55 incorrectly referenced Tab 4 of the RTSR Workform instead of Tab 5,

a) Please confirm whether, in Tab 5, the "Units Billed" are based on 2019 data.

b) If the "Units Billed" in Tab 5 are not based on 2019 data, please update the RTSR Workform so that the Units Billed are based on 2019, the same year as was used for the RRR data in Tab 3.

c) If the "Units Billed" are based on 2019 data, please explain why the values for April and May are not materially higher than in other months (indeed the Line Connection values are actually materially lower) when according to VECC 55 b) WNP was billed by HON for a double peak in each of these months.

WNP's Response:

a) WNP confirms the "Units Billed" in worksheet "5. Historical Wholesale" in the RTSR workform is 2019 data.

b) Not applicable – please refer to response to a).

c) HONI invoices WNP for 3 sub-transmission delivery points that are "Units Billed" (i.e. peak-demand billed):
   1) Hanover TS.
   2) Fergus TS: Arthur PME.
   3) Palmerston TS: Mount Forest South.

   The table below shows the applicable delivery charges applied to each sub-transmission peak-demand billed delivery point:

	Network Charge	Line Connection	Transformation Connection
Hanover TS.	Yes	No	Yes
Fergus TS: Arthur PME.	Yes	Yes	Yes
Palmerston TS: Mount Forest South	Yes	Yes	Yes

On April 1st 2019 HONI switched all load from the Palmerston TS to the Hanover TS. The load was transferred back to Palmerston on May 31st 2019. HONI's monthly invoice is for a calendar month period, i.e. from 1st to 30th/31st. As the load transfer happened on the 1st of the month (April 1st) and then transferred back to normal load on the 31st (May 31st), there were no double-peak demand billed by HONI. The switching was necessary for HONI to complete work at Palmerston TS.

Because Hanover TS delivery point does not have a Line Connection charge (unlike Palmerston TS) the Line Connection "Units Billed" for these months were lower resulting in a reduced Line Connection Amount for both April and May 2019.

The tables below summarizes the Hydro One invoices for 2019 and shows the 2019 monthly details for the Network Charge, the Line Connection Charge and Transformation Connection Charge with this data used to populate the RTSR Model worksheet "5. Historical Wholesale":

Network Charge

Invoice from	Hydro One								
Amount Invoiced:									
Hydro One Delivery Point:	**11086740**	**10684862**	**91975033**			**11086740**	**10684862**	**91975033**	
Location	**Hanover**	**Arthur**	**Palmerston**			**Hanover**	**Arthur**	**Palmerston**	
Unit / Charge	kW			**Total Units Billed**	**Rate**	Tx Rate - Network Charge			**Network Total**
January-19	1,412.45	7,599.36	8,752.20	17,764.01	$ 3.19421	$ 4,511.66	$24,273.94	$27,956.35	56,741.95
February-19	1,334.61	7,198.22	8,284.41	16,817.24	$ 3.19421	$ 4,263.02	$22,992.60	$26,462.12	53,717.74
March-19	1,321.44	7,044.15	8,207.27	16,572.86	$ 3.19421	$ 4,220.96	$22,500.51	$26,215.76	52,937.23
April-19	8,271.95	6,899.27	-	15,171.22	$ 3.19420	$ 26,422.25	$22,037.64	$0.00	48,459.89
May-19	8,309.51	6,799.47	-	15,108.98	$ 3.19420	$ 26,542.24	$21,718.87	$0.00	48,261.11
June-19	2,369.49	6,660.91	6,218.36	15,248.76	$ 3.19420	$ 7,568.63	$21,276.29	$19,862.70	48,707.62
July-19	2,564.29	7,404.24	6,929.16	16,897.69	$ 3.29150	$ 8,440.36	$24,371.05	$22,807.33	55,618.74
August-19	2,471.30	7,451.17	6,505.66	16,428.13	$ 3.29150	$ 8,134.29	$24,525.54	$21,413.40	54,073.23
September-19	2,143.41	7,015.43	6,190.40	15,349.24	$ 3.29150	$ 7,055.03	$23,091.27	$20,375.69	50,521.99
October-19	2,272.70	7,139.40	6,257.13	15,669.23	$ 3.29150	$ 7,480.59	$23,499.33	$20,595.34	51,575.26
November-19	2,632.92	7,055.34	6,538.49	16,226.75	$ 3.29150	$ 8,666.25	$23,222.64	$21,521.42	53,410.31
December-19	2,633.49	7,223.14	6,814.57	16,671.20	$ 3.29150	$ 8,668.12	$23,774.94	$22,430.13	54,873.19
	37,737.56	85,490.10	70,697.65	**193,925.31**		$121,973.40	$277,284.63	$229,640.24	**628,898.27**

The above table illustrates that in April 2019 and May 2019 there was no load on Palmerston TS as HONI transferred all load from Palmerston TS to Hanover TS.

Line Connection Charge

Invoice from	Hydro One								
Hydro One Delivery Point: Location	11086740 Hanover	10684862 Arthur	91975033 Palmerston			11086740 Hanover	10684862 Arthur	91975033 Palmerston	
	kW			Total Units Billed	Rate	Tx Rate - Line Connection			Line Connection Total
January-19		7,599.36	8,752.20	16,351.56	$ 0.77100		$5,859.11	$6,747.95	$12,607.05
February-19		7,198.22	8,284.41	15,482.63	$ 0.77100		$5,549.83	$6,387.28	$11,937.11
March-19		7,044.15	8,207.27	15,251.42	$ 0.77100		$5,431.04	$6,327.81	$11,758.84
April-19		6,899.27	-	6,899.27	$ 0.77100		$5,319.34	$0.00	$5,319.34
May-19		6,799.47	-	6,799.47	$ 0.77100		$5,242.39	$0.00	$5,242.39
June-19		6,660.91	6,218.36	12,879.27	$ 0.77100		$5,135.56	$4,794.36	$9,929.92
July-19		7,404.24	6,929.16	14,333.40	$ 0.78770		$5,832.32	$5,458.10	$11,290.42
August-19		7,451.17	6,505.66	13,956.83	$ 0.78770		$5,869.29	$5,124.51	$10,993.79
September-19		7,015.43	6,190.40	13,205.83	$ 0.78770		$5,526.05	$4,876.18	$10,402.23
October-19		7,139.40	6,257.13	13,396.53	$ 0.78770		$5,623.71	$4,928.74	$10,552.45
November-19		7,055.34	6,538.49	13,593.83	$ 0.78770		$5,557.49	$5,150.37	$10,707.86
December-19		7,223.14	6,814.57	14,037.71	$ 0.78770		$5,689.67	$5,367.84	$11,057.50
	-	85,490.10	70,697.65	**156,187.75**		$0.00	$66,635.79	$55,163.12	**121,798.91**

The above table illustrates that during HONI's load switching 2019 from Palmerston TS to Hanover TS in April 2019 and May 2019, the "Units Billed" were lower as Hanover TS does not charge a Line Connection rate.

Transformation Connection Charge

Invoice from	Hydro One								
Hydro One Delivery Point: Location	11086740 Hanover	10684862 Arthur	91975033 Palmerston			11086740 Hanover	10684862 Arthur	91975033 Palmerston	
	kW			Total Units Billed	Rate	Tx Rate - Transformation Connection Charge			Transformation Connection Total
January-19	1,412.45	7,599.36	8,752.20	17,764.01	$ 1.74930	$2,470.80	$13,293.56	$15,310.22	$31,074.58
February-19	1,334.61	7,198.22	8,284.41	16,817.24	$ 1.74930	$2,334.63	$12,591.85	$14,491.92	$29,418.40
March-19	1,321.44	7,197.05	8,207.27	16,725.76	$ 1.74930	$2,311.59	$12,589.80	$14,356.98	$29,258.37
April-19	8,271.95	6,899.27	-	15,171.22	$ 1.74930	$14,470.12	$12,068.89	$0.00	$26,539.02
May-19	8,309.51	6,799.47	-	15,108.98	$ 1.74930	$14,535.83	$11,894.31	$0.00	$26,430.14
June-19	2,369.49	6,660.91	6,218.36	15,248.76	$ 1.74930	$4,144.95	$11,651.93	$10,877.78	$26,674.66
July-19	2,564.29	7,404.24	6,929.16	16,897.69	$ 1.97550	$5,065.75	$14,627.08	$13,688.56	$33,381.39
August-19	2,471.30	7,451.17	6,505.66	16,428.13	$ 1.97550	$4,882.05	$14,719.79	$12,851.93	$32,453.77
September-19	2,212.43	7,015.43	6,190.40	15,418.26	$ 1.97550	$4,370.66	$13,858.98	$12,229.14	$30,458.77
October-19	2,272.70	7,139.40	6,257.13	15,669.23	$ 1.97550	$4,489.72	$14,103.88	$12,360.96	$30,954.56
November-19	2,632.92	7,055.34	6,538.49	16,226.75	$ 1.97550	$5,201.33	$13,937.82	$12,916.79	$32,055.94
December-19	2,633.49	7,223.14	6,814.57	16,671.20	$ 1.97550	$5,202.46	$14,269.31	$13,462.18	$32,933.96
	37,806.58	85,643.00	70,697.65	**194,147.23**		$69,479.90	$159,607.21	$132,546.45	**361,633.56**

In preparing its' reply to VECC"s pre-settlement question, WNP reviewed all the HONI invoices for 2019. During this review, WNP noted there were inputting errors in the RTSR model for the Transformation Connection Charge. In the table above, the shaded cells represent the corrected data, i.e. what should have been inputted into the RTSR model.

When the corrected Transformation Connection Charge data is input into the RTSR model, the result to the calculated proposed RTSR Network Charge and proposed Connection Charge are:

Comparison: RTSR As Filed and Corrected

Customer Class	RTSR Model Filed with Initial Application **Proposed RTSR Network Charge**	Revised RSTR Model **Updated Propose RTSR Network Charge**	**Change**
Residential	0.0069	0.0069	0.0000
GS <50kW	0.0064	0.0064	0.0000
GS 50-999 kW	2.6635	2.6635	0.0000
GS 1000-4999 kW	2.8290	2.8290	0.0000
USL	0.0064	0.0064	0.0000
Sentinel Lighting	2.0187	2.0187	0.0000
Street Lighting	2.0086	2.0086	0.0000

Customer Class	RTSR Model Filed with Initial Application **Proposed RTSR Connection Charge**	Revised RSTR Model **Updated Propose RTSR Connection Charge**	**Change**
Residential	0.0060	0.0058	-0.0002
GS <50kW	0.0050	0.0048	-0.0002
GS 50-999 kW	2.0404	1.9617	-0.0788
GS 1000-4999 kW	2.2370	2.1507	-0.0864
USL	0.0050	0.0048	-0.0002
Sentinel Lighting	1.6104	1.5484	-0.0620
Street Lighting	1.5777	1.5168	-0.0609

In replying to VECC's pre-settlement conference questions, WNP has provided an updated copy of the RTSR Model that includes the change noted above for all parties to review. (File named 2021 RTSR Model v1.0 EB-2020-0061 Pre-Settlement).

Recommendation:

Given that there is a material change to the Proposed RTSR Connection Charge due to correcting the data in the RTSR model, which in turn affects the projected bill impact for all rate-classes, WNP recommends that, subject to agreement from all parties, a revised version of the RTSR model is filed on the OEB's web portal.