

1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 001**

2  
3 **Reference:**

4 Exhibit A-02-03, Attachment 3, Pages 1 and 26

5  
6 **Interrogatory:**

7 a) Please explain the provision for Vital Services section 2.3.2.I.1.

8  
9 **Response:**

10 Please refer to the section below for an explanation of Vital Services as cited in Hydro One's  
11 Conditions of Service. The relevant excerpt is included below for ease of reference:

12  
**I. Customer Notification of Planned Outages**

Occasionally, Hydro One may need to interrupt a Customer's electrical supply in order to maintain and/or improve the reliability of the Distribution System. For planned power outages, Hydro One notifies Customers in advance by telephone, email, text message, hand-delivered notifications, media alerts or the Hydro One 'Power Outage Map' app.

Prior notification does not apply in Emergency situations.

**I.1 Vital Services**

Customers who rely on electricity for life support equipment should contact our Customer Contact Centre to request that their account be added to our Vital Services list. This list identifies customers who have a life threatening medical need and would be medically affected by a power outage.

Customers must provide medical condition information and consent along with a doctor's certificate. Customers are responsible for ensuring that the information they provide is accurate and up-to-date. Hydro One will conduct an audit of customers on Life Support systems once every three years to ensure that the information on record is accurate and that the service is still required.

Hydro One will attempt to contact critical customers in the event of a planned outage as per section H above or an unplanned service interruption. However, critical customers are encouraged to have a back-up power generation source for these purposes or be able to make alternate arrangements in the event of a power interruption. Hydro One will not be liable in any manner to the Customer for failure to notify in accordance with section H or section H.1 above.

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1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 002**

2  
3 **Reference:**

4 Exhibit A-3-1, Attachment 1, Page 8

5  
6 **Interrogatory:**

7 **Recordable Rate and Serious Injury and Fatality Rate**  
8 ***(Incidents per 200,000 hours worked)***

Year	2019 <i>Actuals</i>	2020 <i>Actuals</i>	2021 <i>Target</i>	2022 <i>Target</i>	2023 <i>Target</i>	2024 <i>Target</i>	2025 <i>Target</i>	2026 <i>Target</i>	2027 <i>Target</i>
<b>Recordable Injury Rate</b>	0.78	0.87	0.92	0.90	0.90	0.90	0.90	0.90	0.90
<b>Serious Injury and Fatality Rate</b>	0.18	0.21	0.11	0.08	0.04	0	0	0	0

9  
10 a) Why is HONI's 'Recordable Injury Rate' target set above the two-year actual incidents (i.e.,  
11 2019 and 2020)?

12  
13 **Response:**

14 Over the 2023-2027 period, Hydro One aims to maintain world-class safety performance with a  
15 Recordable Injury Rate of less than 1.0 recordable injury/illness per 200,000 hours worked.  
16 Maintaining best in class performance at 0.90, as opposed to a continuous improvement is aligned  
17 to the company's strategy of preventing life-altering injuries and fatalities that arise from critical  
18 hazards. Furthermore, zero targets for Recordable Injury have been shown to produce the  
19 unintended consequence of an increase in life-altering and life-threatening injuries, which is  
20 counter to our strategic goals. Hydro One will continue to investigate Recordable Injuries to  
21 identify learning opportunities that further improve our Health and Safety management  
22 processes and practices.

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1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 003**

2  
3 **Reference:**

4 Exhibit A-3-1, Attachment 1, Page 8, Table 12 and 13

5  
6 **Interrogatory:**

7 a) In the Business Plan the Transmission revenue requirement for 2023 (\$1,764M) is lower than  
8 that applied for in this application (\$1,823.2). Similarly, the 2023 Business Plan Distribution  
9 Revenue requirement (\$1,538M) is lower than that applied for (\$1,632.4). Please explain the  
10 reasons for the material differences as between the Business Plan and what has been applied  
11 for in this Application.

12  
13 **Response:**

14 a) Hydro One confirms that there are no material differences in revenue requirement as outlined  
15 in the Business Plan presented in Exhibit A-03-01 Attachment 1 (Business Plan) relative to the  
16 current application.

17  
18 The Transmission revenue requirement figure stated in this interrogatory of \$1,764M reflects  
19 rates revenue requirement found in the Business Plan and not revenue requirement. Exhibit  
20 D-01-01 page 3 shows Transmission revenue requirement of \$1,823.2M, which reconciles to  
21 the revenue requirement line within the Business Plan (pre-other).

22  
23 The Distribution figure stated in this interrogatory of \$1,632.4M is referencing rates revenue  
24 requirement excluding the Acquired Utilities found in the Business Plan and not revenue  
25 requirement that is being compared. Exhibit D-01-01 page 8 shows Distribution revenue  
26 requirement of \$1,632.4M, which reconciles to the revenue requirement line within the  
27 Business Plan (pre-other) of \$1,602M + \$30M related to the Acquired Utilities.

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Witness: JODOIN Joel

1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 004**

2  
3 **Reference:**

4 Exhibit A-3-1, Attachment 1, Page 54

5 Exhibit E-6-1, Section 3.4.1

6  
7 **Interrogatory:**

8 a) Please provide the sum of the costs removed from revenue requirement subject to Bill 2 and  
9 voluntary ELT reductions in each of the years 2019 through 2027.

10  
11 **Response:**

12 a) In the Hydro One's Distribution Application, approximately \$6.6M in executive compensation  
13 costs have been removed per year from 2019-2022.

14  
15 In the Hydro One's Transmission Applications, approximately \$2.2M in executive  
16 compensation costs have been removed in 2019 (as it was an inflationary application based  
17 on 2018 approved costs), while approximately \$4.4M per year have been removed from 2020-  
18 2022.

19  
20 For 2023-2027, approximately \$9.5M per year in executive compensation costs have been  
21 removed from this rate application (on a combined basis between Transmission and  
22 Distribution).

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1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 005**

2  
3 **Reference:**

4 Exhibit A-4-1, Page 1

5 Exhibit A-4-2

6 Exhibit A-4-3

7  
8 **Interrogatory:**

9 a) In the Custom IR formula,  $RCI=I-X+C$ , the inflation factor 'I' is based on a custom weighted  
10 two-factor input price index. The weightings of the two factors are different for Transmission  
11 as compared to Distribution. What is the basis for a difference between the two operating  
12 units? Specifically, the labour component of 30% for distribution and 14% for transmission  
13 implies there is more than a 100% difference in the labour allocated to the distribution  
14 function. Please show how the allocation of labour as between transmission and distribution  
15 is demonstrative of their weighting used in the inflation calculation.

16  
17 b) The OEB is reviewing its default inflation two factor inflation estimator due to anomalous  
18 results of the Average Weekly Earnings component. Is it the intention of HONI to apply the  
19 methodology approved by the Board in that proceeding?

20  
21 **Response:**

22 a) For the Distribution business, Hydro One has aligned with the OEB's December 2013 Report,  
23 "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for  
24 Ontario's Electricity Distributors" (EB-2010-0379), in which the OEB established a  
25 methodology for determining the annual Inflation Factor (I) to be used in incentive-based rate  
26 adjustment mechanisms for electricity distributors. Specifically, that the Inflation Factor is  
27 based on the weighted sum of 30% labour and 70% non-labour.

28  
29 For its Transmission business, Hydro One is proposing an Inflation Factor (I) based on the  
30 industry-specific weighting of 14% labour and 86% non-labour. This weighting was supported  
31 by the independent analysis conducted for Hydro One by Power System Engineering (PSE),  
32 which was included as Attachment 1 in Exhibit A-4-1 of EB-2019-0082, and approved by the  
33 OEB in both EB-2018-0218 and EB-2019-0082. The weightings were also adopted by the OEB  
34 in its November 9, 2020 letter setting out inflation parameters for utilities.

35  
36 The lower labour weighting in the Transmission business is more representative of the very  
37 capital-intensive nature of the transmission business.

Witness: VETSIS Stephen

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- 1 b) Please see response to A-SEC-011.

1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 006**

2  
3 **Reference:**

4 Exhibit A-4-1  
5 Exhibit A-4-2  
6 Exhibit A-4-3  
7

8 **Interrogatory:**

- 9 a) The Distribution and Transmission RCI formulas also differ in the calculation of the  
10 productivity factor (X-factor). For distribution an x-factor of 0.3% is proposed. For  
11 transmission no X-factor is proposed (i.e., 0%). However, a number of costs, including  
12 Common and Other OM&A and Common Corporate Functions apply to both transmission and  
13 distribution functions. What is the underlying rationale for applying different x-factors to  
14 common cost allocated to each of utility function? Specifically, please explain the rationale  
15 for having the portion of common costs allocated to distribution subject to an incentive factor  
16 but the portion allocated to transmission not.  
17
- 18 b) If an x-factor of 0.3% were applied to all common costs which are allocated to the  
19 transmission function what change would this have on that annual revenue requirement of  
20 TX? Please use Exhibit A-3-1 Table 17 and A-4-2-Table 1 Summary of Revenue Requirement  
21 Components for Hydro One Transmission to show any differences.  
22

23 **Response:**

- 24 a) Response from Clearspring:  
25

26 The common costs allocated to both transmission and distribution are subject to an incentive  
27 factor. Hydro One's total transmission costs, which include a portion of common costs, are  
28 found to be at low-cost levels based on the Clearspring study, and so while the stretch factor  
29 for transmission is recommended to be 0.0%, this is a number derived from rigorous research  
30 (and a number in the range of allowable stretch factors). That the recommended number is  
31 0.0% does not mean that "no X-factor is proposed"—an X-factor equal to 0.0 is proposed  
32 based on the econometric benchmarking results.  
33

34 The study included common costs for Hydro One and the sample of utilities because this is  
35 the most comprehensive method of examining cost levels and their benchmarks. Including  
36 common costs within the cost definition of transmission or distribution for a total cost  
37 benchmarking study is best practice. If they were not included the study would not only be

1 less comprehensive in its scope of costs that cover the revenue requirement but would also  
 2 be less accurate because excluding common costs could insert uncontrolled for differences  
 3 with utilities classifying expenses differently between common and transmission/distribution.  
 4

5 b) Consistent with the response to part a) above, Hydro One does not agree that a separate X-  
 6 factor should apply to common costs. Please see below for a table that provides the annual  
 7 transmission revenue requirement impact of applying a 0.3% productivity factor to common  
 8 assets and costs allocated to the transmission function. Hydro One notes that the differences  
 9 are immaterial.  
 10

(\$M)	2023	2024	2025	2026	2027
Revenue Requirement associated with Common Assets and Costs <i>0.3% productivity factor</i>	100.2	118.7	125.2	147.7	160.6
Revenue Requirement without Common Assets and Costs <i>0.0% productivity factor</i>	1,723.0	1,818.8	1,901.6	1,991.4	2,056.7
<b>Total Revenue Requirement</b>	<b>1,823.2</b>	<b>1,937.5</b>	<b>2,026.8</b>	<b>2,139.1</b>	<b>2,217.4</b>
JRAP Revenue Requirement	1,823.2	1,937.8	2,2027.5	2,140.3	2,219.0
<b>Revenue Requirement Impact of Applying a 0.3% Productivity Factor to Transmission Common Assets and Costs</b>	<b>0.00</b>	<b>-0.35</b>	<b>-0.73</b>	<b>-1.18</b>	<b>-1.68</b>

1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 007**

2  
3 **Reference:**

4 Exhibit A-4-1, Page 6

5 Exhibit G-1-2

6  
7 **Interrogatory:**

8 a) HONI proposes different treatments of the proposed CISVA accounts for Distribution and  
9 Transmission. CISVA Distribution is subject to an annual true-up whereas CISVA  
10 Transmission has a true-up at the end of the rate plan term. Please explain the reasoning  
11 for the different treatments.

12  
13 b) Does the 2% dead band apply equally to both DX and TX CISVA accounts?

14  
15 **Response:**

16 a) Hydro One would like to clarify that it does not agree with the use of the term “true-up” to  
17 describe the request to catch up on in-service additions throughout the term period.

18  
19 The difference in treatments is attributable to the nature of the investments, which are  
20 different for Distribution and Transmission. Distribution investments are largely defined by a  
21 programmatic structure which is focused on discrete annual work plans (though in more  
22 recent years this has been changing somewhat and the work plans are becoming more  
23 complex). In contrast, as explained in Section 4.3 of Exhibit G-01-02, Transmission  
24 investments are typically large in scale, complex and multi-year in nature. The different  
25 characteristics of the work in Transmission as compared to Distribution, based on Hydro  
26 One’s experience, has informed the requested approach to the Transmission CISVA.  
27 Furthermore, as noted in Exhibit G-01-02, while Hydro One is open to having the  
28 Distribution CISVA operate in the same manner for consistency, it is only proposing this  
29 modified revenue requirement calculation for its Transmission CISVA because of its  
30 recognition that the issue being addressed by the modification is uniquely relevant to the  
31 Transmission business.

32  
33 b) Yes.

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1 **A - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 008**

2  
3 **Reference:**

4 Exhibit A-4-2, Table 1 Tx, Page 5-6

5 Exhibit A-4-3, Table 1 Dx, Page 5

6  
7 **Interrogatory:**

8 a) Please show how the removal of working capital from the capital factor (Table 1/Line 1) is  
9 calculated.

10  
11 b) Please show how line 12 is calculated (for example why is line 12 the same as line 8 in 2024?).

12  
13 c) Please respond to a) and b) for the equivalent DX table.

14  
15 **Response:**

16 a) A detailed calculation of the removal of working capital from the capital factor is provided in  
17 part e) of Hydro One's response to A-Staff-7.

18  
19 b) A live Excel version of Table 1 is provided as Attachment 1 to A-Staff-7. While the working  
20 capital allowance is not included in the C-factor, some allowance for working capital is still  
21 included in the total revenue requirement at the time of rebasing. Through the calculation  
22 referred in part a) of this response, Hydro One ensures that line 11 adjusts the amount of  
23 working capital in the revenue requirement each year such that it is equal to the base amount  
24 in 2023 escalated by I-X and that no amounts are included for working capital in the C-factor,  
25 consistent with prior OEB decisions. In 2024, line 12 in the Transmission Custom IR table  
26 appears the same as line 8 because the magnitude of the adjustments in lines 9-11 happens  
27 to be roughly equal to the base amount of working capital that continues to be a part of the  
28 total revenue requirement.

29  
30 c) The table for the distribution table operates in the same way as the transmission table. Please  
31 see the responses to a) and b) above for a description of the table mechanics.

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Category	Investment ISD	Investment ISD Name
<b>System Renewal</b>		
<b>Integrated Station Investment</b>	T-SR-01	Transmission Station Renewal - Network Stations
	T-SR-02	Transmission Station Renewal - Air Blast Circuit Breakers
	T-SR-03	Transmission Station Renewal - Connection Stations
<b>Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects</b>	T-SR-04	Wood Pole Structure Replacements
	T-SR-05	Steel Structure Coating Program
	T-SR-06	Tower Foundation Assess/Clean/Coat & Life Extension Program
	T-SR-07	Transmission Line Shieldwire Replacement
	T-SR-08	Transmission Line Insulator Replacement
	T-SR-13	Transmission Line Complete Refurbishment
	T-SR-15	Transmission Line Emergency Restoration
<b>Protection and Automation</b>	T-SR-10	Protection Relay Replacement Program
	T-SR-11	Legacy SONET System Replacement
	T-SR-12	Telecom Performance Improvements
	T-SR-14	Mobile Radio System Replacement
	T-SR-17	OPGW Infrastructure Projects
<b>Tx Transformers Demand and Spares</b>	T-SR-09	Transmission Station Demand and Spares and Targeted Assets
<b>Underground Lines Cable Refurbishment &amp; Replacement</b>	T-SR-16	HV UG Cable – Replace/Refurbish Pumping Plants
	T-SR-18	C5E/C7E Underground Cable Replacement

1

Category	Investment ISD	Investment ISD Name
<b>System Service</b>		
<b>Inter Area Network Capability</b>	T-SS-01	Nanticoke TS: Connect HVDC Lake Erie Circuits
	T-SS-02	St. Lawrence TS: Phase Shifters Replacement
	T-SS-03	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade
	T-SS-07	West of Chatham Reinforcement
	T-SS-09	West of London Reinforcement
<b>Local Area Supply Adequacy</b>	T-SS-04	Richview x Trafalgar 230kV Conductor Upgrade
	T-SS-05	Merivale TS Add 230/115kV Autotransformers
	T-SS-06	Southwest GTA Transmission Reinforcement
	T-SS-08	Future Transmission Regional Plans



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Witness: FALTAOUS Peter



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1

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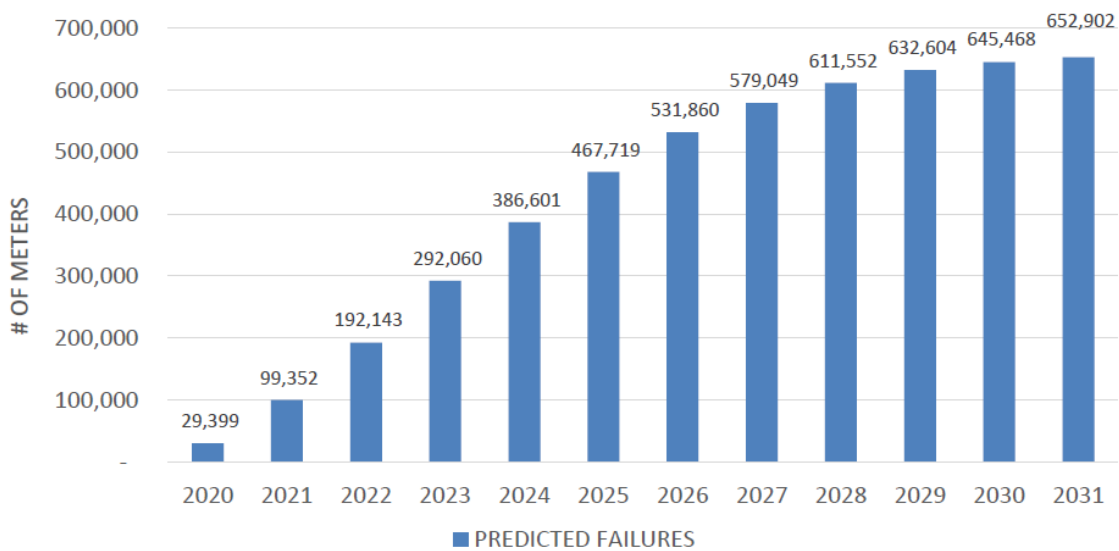
Witness: PAISH David

1 **B3 - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY -**  
2 **012**  
3

4 **Reference:**

5 Exhibit B-3-1, DSP Section 3.11, SR-12  
6

7 **Interrogatory:**



1 **Figure 2: Projected Accumulated GEN 1 Meter Failures Based On ALT Results at the 50%**  
2 **Confidence Level**

8

9 a) Given the magnitude of the project why did Hydro One not choose to use the regulatory  
10 constructs of the ACM or ICM for the AMI program?

11

12 b) Please provide the actual meter failures in 2020 and 2021 (to-date).

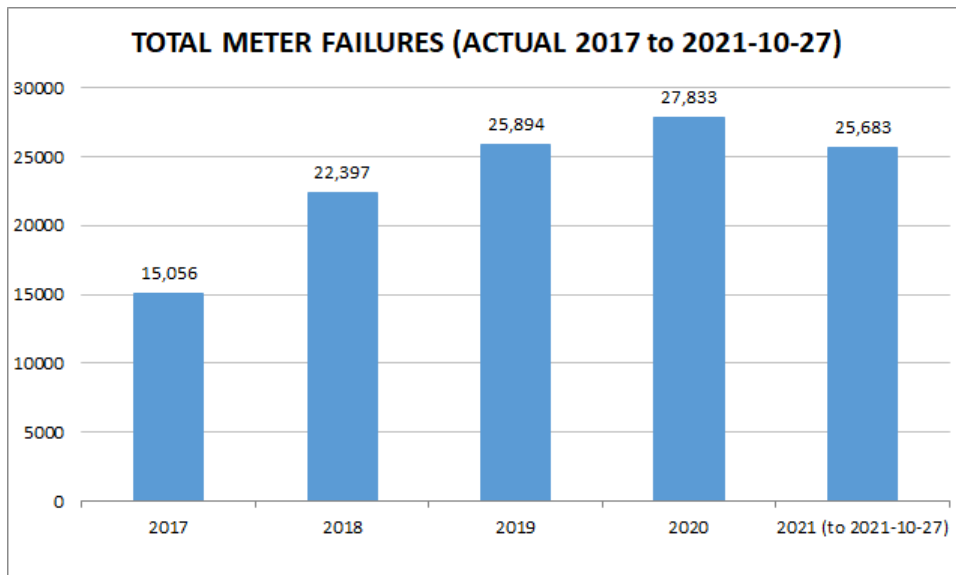
13

14 c) Please provide a list of the IT systems with operational interdependency to the AMI system.  
15 For each of these IT systems please note if and when an upgrade to that system will be  
16 required in conjunction with AMI 2.0; the timing of that update and its estimated cost.

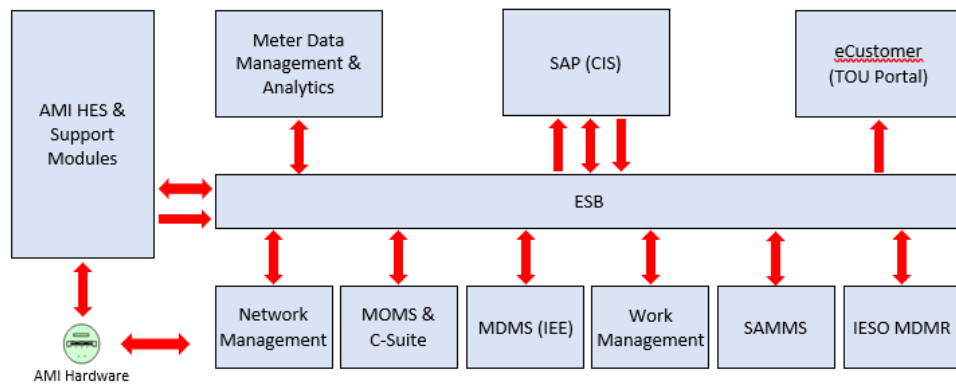
**Response:**

a) Hydro One's application is a Custom IR. The ICM and ACM mechanisms for funding capital projects are not available to utilities pursuing a Custom IR application.

b) The total number of meter failures issued up to October 27, 2021 is provided in the Figure below.



c) IT systems with operational interdependencies to the AMI system are set out in the figure below:





1 No major upgrades, apart from the replacement of the AMI 2.0 Head End System (HES), have  
2 been identified to interdependent AMI 2.0 systems. The estimated costs associated with  
3 standard enhancements of integrating the AMI 2.0 HES to related systems are provided in the  
4 table below. The structured approach to designing, building, integrating, and testing the AMI  
5 2.0 HES (see D-SR-12 Section C.3, Table 4) is planned for the period Q3 2022 through Q2 2023.  
6

Year	Pre-Test		Test Period					Post-Test	Total
	2021	2022	2023	2024	2025	2026	2027	2028	
IT Integration	\$0	\$2.0M	\$6.4M	\$0	\$0	\$2.2M	\$0	\$1.7M	\$12.2M

7

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Witness: PAISH David



1 For System Operations, the timing is related to managing assets that are at or are nearing the end  
2 of vendor support, as discussed in GSP Section 4.8, page 4, lines 16 to 20:

3  
4  
5  
6  
7  
8  
9

*This trend reflects the upgrade of all critical systems applications that are or are  
nearing the end of vendor support, including the Network Management System,  
Outage Response Management System and Distribution Management System.  
Details on the System Operations investments can be found in GSP Section 4.11,  
G-GP-12 through G-GP-18.*

10 The investment levels in other GSP functions, such as Fleet, are relatively stable year over year  
11 between 2023-2027. The proposed investments are paced to help ensure that safe, reliable and  
12 functional General Plant assets are available to enable the Transmission and Distribution  
13 businesses to execute their work programs and achieve their strategic objectives. For additional  
14 details on the investment levels for each General Plant function, please refer to GSP Section 4.8,  
15 pages 2-5.

1 **B4 - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY -**  
 2 **014**

3  
 4 **Reference:**

5 Exhibit B-4-1, GSP Section 4.11, G-GP-01

6  
 7 **Interrogatory:**

8  
 9 **Table 1 - Forecast of Acquisitions for 2023 to 2027 (\$M)**

Equipment Type	2023	2024	2025	2026	2027
Light & Heavy Non-PTO <sup>1</sup>	21.8	21.8	21.3	21.7	21.7
Heavy PTO <sup>2</sup>	25.7	28.3	25.5	25.8	28.8
Off-Road <sup>3</sup>	6.0	6.7	7.0	7.3	5.5
Miscellaneous <sup>4</sup>	5.2	3.3	6.8	6.7	7.8
Small Off-Road <sup>5</sup>	2.0	2.1	2.1	2.2	2.2
Service Equipment <sup>6</sup>	6.4	6.5	6.6	6.8	6.9
<b>Total<sup>7</sup></b>	<b>67.2</b>	<b>68.7</b>	<b>69.3</b>	<b>70.4</b>	<b>72.8</b>

10

11 a) Please provide the equivalent table for the period 2017-2022.

12

13 b) Given the worldwide shortage in vehicle production what adjustment has Hydro One made  
 14 to its vehicle acquisition plans for 2022 and 2023?

15

16 **Response:**

17 a)

Equipment Type	Actuals				Forecast	
	2017	2018	2019	2020	2021	2022
Light & Heavy Non-PTO	14.3	0.1	14.1	6.0	15.6	11.5
Heavy PTO	10.9	15.4	12.3	11.8	15.6	10.5
Off-Road	10.5	2.3	1.6	5.8	1.9	3.1
Miscellaneous	5.7	1.3	3.2	0.9	0.9	0.9
Small Off-Road	0.9	0.7	1.7	1.9	2.0	2.0
Service Equipment <sup>1</sup>	5.6	7.6	6.2	7.6	6.2	6.4
<b>Total</b>	<b>47.9</b>	<b>27.4</b>	<b>39.1</b>	<b>34.0</b>	<b>42.2</b>	<b>34.4</b>

<sup>1</sup> In 2017 and 2018, Service Equipment included helicopters.

Witness: BERARDI Rob

- 1 b) No adjustments to the vehicle acquisition plans for 2022 and 2023 have been made. 2022
- 2 ordering is in process and commitments with equipment manufacturers are being placed for
- 3 2023. Hydro One is also working closely with the manufactures to ensure the delivery
- 4 schedule will be met and any risk is identified.

1 **B4 - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY -**  
 2 **015**  
 3

4 **Reference:**

5 Exhibit B-4-1, GSP Section 4.11, G-GP-01  
 6

7 **Interrogatory:**  
 8

Proposed Funding	2021	2022	2023	2024	2025	2026	2027
Annual Capital	\$26,238,742	\$26,580,590	\$58,751,660	\$60,020,550	\$60,663,270	\$61,543,910	\$63,694,290
Units Replaced	253	258	554	556	549	551	556
Annual Maintenance	\$60,575,690	\$62,733,890	\$62,506,600	\$62,643,440	\$62,844,990	\$63,017,950	\$63,166,600
Annual ownership	\$34,798,810	\$33,225,780	\$37,439,450	\$41,045,210	\$44,099,020	\$46,744,460	\$49,271,810
<b>Total</b>	<b>\$95,374,500</b>	<b>\$95,959,670</b>	<b>\$99,946,050</b>	<b>\$103,688,700</b>	<b>\$106,944,000</b>	<b>\$109,762,400</b>	<b>\$112,438,400</b>
Out of Life	1,582	1,923	1,936	1,981	1,978	1,814	1,827
AvgAge	9.77	10.02	9.70	9.52	9.38	9.26	9.14

9

10

**Table 3 - Total Investment Cost**

(\$M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	67.2	68.7	69.3	70.4	72.8	348.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
<b>Capital and Minor Fixed Assets</b>	<b>67.2</b>	<b>68.7</b>	<b>69.3</b>	<b>70.4</b>	<b>72.8</b>	<b>348.5</b>
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
<b>Net Investment Cost</b>	<b>67.2</b>	<b>68.7</b>	<b>69.3</b>	<b>70.4</b>	<b>72.8</b>	<b>348.5</b>

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17

18

a) Please clarify how the investment costs in Table 3 relate to the Annual Capital costs shown in the various Utilmarc tables – that is, is the Annual Capital Line in the Utilmarc study the equivalent comparator to the Gross Investment Line in Table 3?

**Response:**

The Utilmarc tables do not include Small Off-Road and Service Equipment. Table 3 – Total Investment Cost is the total of all the G-GP-01 investments.

Filed: 2021-11-29  
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Witness: BERARDI Rob





Filed: 2021-11-29  
EB-2021-0110  
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Witness: HOLDER Godfrey



1 **Response:**

- 2 Please refer to GSP Section 4.11, G-GP-10 page 9, line 25-26, and page 10, line 1. The two critical  
3 CIP-014 stations will follow the completion of the 2022 program hence the higher spend in 2023.  
4 Spreading the investment amount across 2023/2024 impacts NERC CIP compliance commitments  
5 and represents increased risk to the critical stations which will be delayed by one year.

1 **C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 018**

2  
3 **Reference:**

4 Exhibit C-1-1, Page 2

5  
6 **Interrogatory:**

7  
8 **Table 2 - 2022 OEB-approved versus 2022 Forecast Year Rate Base (\$M)**

Rate Base Component	2022	2022	Variance
	Forecast	OEB-approved	
Mid-Year Gross Plant	21,597.7	21,545.1	52.6
Less: Mid-Year Accumulated Depreciation	(7,941.4)	(7,943.9)	2.5
<b>Mid-Year Net Utility Plant</b>	<b>13,656.3</b>	<b>13,601.2</b>	<b>55.1</b>
Cash Working Capital	24.1	27.3	(3.2)
Materials & Supply Inventory	13.9	12.4	1.5
<b>Total Rate Base</b>	<b>13,694.2</b>	<b>13,640.9</b>	<b>53.3</b>

- 9  
10 a) Why is Hydro One forecasting more TX in-service additions (\$52.6M) in 2022 than the Board  
11 approved amount? Specifically, why is HONI not modifying its 2002 capital program to meet  
12 the Board approved amounts for 2022?

13  
14 **Response:**

- 15 a) Hydro One is forecasting to in-service approximately \$83M more capital during the current  
16 2020-2022 rate period, which contributes to a mid-year net plant rate base variance of  
17 approximately \$55M. Also included within the mid-year net plant are Asset Retirements,  
18 Sales, and Transfers.

19  
20 The variance to in-service additions is primarily driven by an increase to the scope and  
21 complexity of Lakeshore TS, originally presented as part of the Leamington Area Transmission  
22 Reinforcements (ISD SS-13 as part of EB-2019-0082), due to IESO recommendations and  
23 increased technical requirements. This has resulted in an approximately \$83M variance to the  
24 cumulative approved in-service additions.

1 Hydro One has revised the pacing of System Renewal in-service additions lower to minimize  
2 the overall in-service addition variance. The System Renewal portfolio has been reduced by  
3 over \$200M relative to OEB-approved levels over the 2020-2022 period. Further  
4 modifications to the 2022 capital work program would place undue risk to the safe and  
5 reliable operation of the power system. Given the multi-year nature of many transmission  
6 projects, a significant portion of the portfolio is in execution; reducing this work would result  
7 in additional, and unnecessary costs.

**C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 019**

**Reference:**

Exhibit C-1-1, Page 7

**Interrogatory:**

**Table 7 - 2022 OEB-approved versus 2022 Forecast Year Rate Base (\$M)**

Rate Base Component	2022	2022	Variance
	Forecast	OEB-approved	
Mid-Year Gross Plant	13,941.7	14,152.7	(211.0)
Less: Mid-Year Accumulated Depreciation	(5,411.5)	(5,692.6)	281.1
<b>Mid-Year Net Utility Plant</b>	<b>8,530.2</b>	<b>8,460.0</b>	<b>70.2</b>
Cash Working Capital	308.4	338.2	(29.8)
Materials & Supply Inventory	5.9	5.5	0.4
<b>Total Rate Base</b>	<b>8,844.5</b>	<b>8,803.7</b>	<b>40.8</b>

- a) Why is Hydro One forecasting more DX in-service additions (\$211.0M) in 2022 than the Board approved amount? Specifically, why is HONI not modifying its 2002 capital program to meet the Board approved amounts for 2022?

**Response:**

- a) Hydro One is forecasting to in-service approximately \$61M more capital in Distribution during the current rate period (2018-2022) as evident from Table 1 in Exhibit C-02-02; this contributes to a mid-year net plant rate base variance of approximately \$70M. The referenced figure of \$211M which is the variance in Mid-Year Gross Plant also includes Asset Retirements, Sales, and Transfers. Retirement variances would have an offsetting impact in accumulated depreciation, therefore it is most appropriate to review the mid-year net utility plant variance of \$70M.

As noted in Exhibit C-02-02, during the current rate period, 2018-2022, Hydro One has experienced significant volumes of System Access requests, as a result of new customer connections and service upgrades, joint use and relocation requests, and meter replacements. System Access expenditures are non-discretionary investments that Hydro One

1 is obligated to perform as a distributor to be compliant with applicable codes, standards, laws,  
2 or regulations. Through the end of the current rate period, System Access investment  
3 variances are forecast to exceed the implicit approved category envelope by approximately  
4 \$155M, or about 20%.

5  
6 In response to this significant demand, Hydro One has reduced System Renewal and System  
7 Service investments by approximately 4% and 18% respectively, on an in-service addition  
8 basis, through deferrals and the introduction of cost-effective alternative work methods, such  
9 as wood pole refurbishments. Despite ongoing efforts focused on renewing the system and  
10 managing the capital envelope, there is a significant population of deteriorated assets that  
11 remain unaddressed, presenting risk to safe and reliable operations. Further reductions were  
12 deemed to not be prudent.

13  
14 A number of System Service investments have also been deferred to manage the overall  
15 envelope and respond to the System Access requests. The net effect of these deferrals is  
16 somewhat muted, as a result of significant and unanticipated investment requirements in the  
17 Leamington area. Since the last application, the electrification of the agriculture sector in the  
18 Leamington area has expanded rapidly, leading to close to 1,400 MW of connection requests.  
19 This level of growth has triggered both substantial local distribution capability  
20 reinforcements, as well as broader upstream transmission infrastructure investments. As a  
21 result of this growth, Hydro One had to increase investments beyond the previously adjusted  
22 System Service levels, contributing to the overall distribution in-service addition variance of  
23 approximately \$61M over the current rate period.



1 **C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 020**

2  
3 **Reference:**

4 Exhibit C-3-1/8

5 Exhibit E-4-8, Page 3

6  
7 **Interrogatory:**

- 8 a) HONI has used the same consulting firm to review the Corporate Cost Allocation and the  
9 Overhead Capitalization Methodology (i.e., Black& Veatch or 'B&V'). Please explain why the  
10 runner up to the RFP was rejected. What weight was given to obtaining an opinion  
11 unrelated to the original authorship?  
12
- 13 b) Do the original and the new B&V studies have any common authorship?  
14
- 15 c) At Exhibit E-4-8, page 3 it refers to the ***"2023 Black and Veatch report (2023 B&V Study)***  
16 ***provided as Attachment 1..."*** Please confirm this refers to the attached study dated June 9,  
17 2021 and referred to therein as the Corporate Cost Allocation Review – 2020, i.e., there is  
18 no other study being referred to?  
19

20 **Response:**

- 21 a) Exhibit E-04-08 summarizes the RFP process to review the Corporate Cost Allocation and  
22 Overhead Capitalization methodologies. Furthermore, the exhibit outlines that Black &  
23 Veatch was selected with a new lead expert for the study, and a mandate to take a fresh,  
24 detailed and critical look at the methodologies and to refine them where appropriate on the  
25 basis of best practises.  
26

27 All candidates were evaluated by a panel using the same criteria, with different weightings  
28 applied to experience performing similar work in the past, experience as an expert witness,  
29 clarity of proposed approach/methodology, proper understanding of Hydro One's  
30 requirements and pricing. Based on the established criteria, the runners up scored lower in  
31 their evaluation criteria than Black & Veatch.  
32

- 33 b) No. The main author of the original report was Howard Gorman. Russ Feingold became  
34 involved after joining Black & Veatch in 2007. While Mr. Feingold reviewed the current  
35 report upon completion, he was not a contributing author and retired from Black & Veatch  
36 earlier in 2021. The main author of the current report is John Taylor. Hydro One notes that  
37 while Mr. Taylor was employed by Black & Veatch at the beginning of the engagement,

1           during the course of the engagement he left to join Atrium Economics. He completed  
2           preparation of the current report as a subcontractor to Black & Veatch and continues to  
3           support the current report as an expert through a separate concurrent engagement directly  
4           with Atrium. Notwithstanding these arrangements, Hydro One continues to refer to the  
5           report and associated responses as being from Black & Veatch.

6

7   c) Confirmed.

1 **C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 021**

2

3 **Reference:**

4 Exhibit C-6-1

5

6 **Interrogatory:**

7

8

**Table 1 - Inventory Levels 2018 – 2027 (\$M)**

Year	Historical				Bridge	Forecast				
Year End Balances	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Materials and Supplies	16.4	17.5	18.5	19.5	19.9	20.3	20.7	21.2	21.6	22.0
Allocated to Transmission	11.8	12.0	13.1	13.7	14.0	14.3	14.6	14.8	15.1	15.4
Allocated to Distribution	4.6	5.5	5.4	5.8	5.9	6.1	6.2	6.3	6.4	6.6

9

10 a) HONI explains the increase in inventory as attributable to inflation. Using CPI (Bank of  
 11 Canada) the 2018 actual materials and supply amount would be today \$17.53M as compared  
 12 to the forecast of \$19.5M. This is significantly above what would be expected from  
 13 inflationary pressures. What are the other reasons explaining the increase in the material  
 14 supplies from 2018 as compared to today?

15

16 b) Please explain what steps are taken by HONI to minimize the need to carry inventory.

17

18 c) Has HONI experienced any shortages of materials and supplies due to the ongoing pandemic?  
 19 If so please comment on how the pandemic has affected Hydro One’s inventory strategy.

20

21 **Response:**

22 a) The increase in inventory is attributable primarily due to a combination of higher unit pricing  
 23 due to inflationary pressures, and additional quantities of material on hand, required to  
 24 support the growth of work program. There are increased inventory levels for distribution  
 25 due to delivery date delays and increased inventory due to security of supply.

26

27 b) Hydro One annually reviews the inventory for items that have become slow moving or  
 28 obsolete. For large capital projects, material is ordered direct to projects reducing the need  
 29 to hold inventory.

Witness: BERARDI Rob

- 1 c) Yes, Hydro One has experienced shortages of materials and supplies due to the ongoing
- 2 pandemic. To help manage shortages of materials and supplies due to the ongoing pandemic
- 3 Hydro One has implemented an assurance of supply strategy as outlined in Exhibit E-05-02.

1 **C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 022**

2

3 **Reference:**

4 Exhibit C-8-2

5

6 **Interrogatory:**

7

8 **Table 1 - Overhead Capitalization Rates and Amounts for Transmission and Distribution**

9

Overhead Cost Category	Test Years (%)					Test Years (\$M)				
	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
Transmission	8.0%	8.0%	9.0%	9.0%	9.0%	118.1	119.7	121.0	122.3	123.9
Distribution	9.0%	9.0%	9.0%	9.0%	9.0%	89.9	91.0	94.9	94.2	95.7

10

11 a) Please provide the historical amounts for Table 1 (i.e., 2017 through 2022 (forecast)).

12

13 **Response:**

14 Please see the response to interrogatory C-SEC-180.

Filed: 2021-11-29  
EB-2021-0110  
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Tab 24  
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Page 2 of 2

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Witness: CHHELAVDA Samir

1 **C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 023**

2  
3 **Reference:**

4 Exhibit C-8-2, Appendix 2-D

5  
6 **Interrogatory:**

7 a) Hydro One Transmission's percentage of capitalized OM&A is on average double that for  
8 Distribution (about 12% vs 24%). In general terms, what accounts for the very different levels  
9 of OM&A capitalization as between these two operations?

10  
11 **Response:**

12 The percentage of capitalized OM&A is calculated by taking Total Capitalized OM&A (row A in  
13 Exhibit C-08-02, Appendix 2-D) divided by Total OM&A Before Capitalization (row B in Exhibit C-  
14 08-02, Appendix 2-D).

15  
16 Exhibit E-04-08, Attachment 1, outlines the Black & Veatch overhead capitalization methodology  
17 which results in higher Total Capitalization OM&A for Hydro One Transmission on average  
18 compared to Distribution (\$118M vs \$85M from 2018-23). Additionally, Hydro One Transmission's  
19 Total OM&A Before Capitalization is lower on average compared to Distribution (\$514.5M vs  
20 \$642.6M from 2018-23). Together, these two factors have resulted in Hydro One Transmission  
21 having a percentage of capitalized OM&A that is approximately double on average than that of  
22 Distribution (23% vs 13% from 2018-23).

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1 **C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 024**

2

3 **Reference:**

4 Exhibit C-8-2, Attachment 1, Page 4

5

6 **Interrogatory:**

7 *"Of particular significance is that Hydro One self-constructs most of their capital work. In our*  
8 *experience, this is in contrast to many of its peers which generally perform more construction*  
9 *activity"*

10

11 a) What is the evidentiary basis for the claim that Hydro One self-constructs more than its peers?

12

13 **Response:**

14 Response Provided by PwC:

15 Please see Interrogatory Response **C-Staff-182**, part d).

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1 **C - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 025**

2

3 **Reference:**

4 Exhibit C-9-3

5

6 **Interrogatory:**

7

8 **Table 1 - Transport and Work Equipment**  
 9 **(\$M)**

Description	Historic				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Operations & Repairs	67.7	71.1	77.4	76.4	79.5	82.3
Fuel Costs	27.2	24.4	22.2	26.0	26.0	26.0
Depreciation	40.3	41.8	42.6	45.3	45.3	45.8
<b>Subtotal</b>	<b>135.2</b>	<b>137.2</b>	<b>142.2</b>	<b>147.7</b>	<b>150.8</b>	<b>154.1</b>
Rentals	0.5	0.9	1.9	2.0	2.0	2.0
<b>Totals</b>	<b>135.7</b>	<b>138.2</b>	<b>144.1</b>	<b>149.7</b>	<b>152.8</b>	<b>156.1</b>

10

11 a) Hydro One states that “There was an overall 4% increase in fleet asset-related expenditures  
 12 in 2020 from 2019 due to an increase in Operations and Repairs that was due to an increase  
 13 in external labour rates”. Please provide more information on the nature of the increase in  
 14 external labour rates.

15

16 **Response:**

17 Automotive Resources International (ARI), Hydro One Vendor for the Fleet Management System,  
 18 has stated that labour shortages are causing an increase to labour rates. A deficiency of labourers  
 19 has added to the shortages we are seeing. Without people to perform the labour, the  
 20 manufacturing industry is unable to keep up with demand. To keep the workers from leaving their  
 21 current job to look elsewhere, businesses have been forced to increase wages in order to stay  
 22 competitive. Those increases are then being passed on to the end consumer by pricing increases.  
 23 These can come in the form of higher parts pricing since the component costs more to make or  
 24 higher labour rates. Year to date, ARI has recognized a 3% increase in the average labour rate.  
 25 Furthermore, the average labour rate has increased 7% comparing August 2021 to August 2020.

Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
Schedule C-VECC-025  
Page 2 of 2

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Witness: BERARDI Rob

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 026**

2  
3 **Reference:**

4 Exhibit D-2-1, Page 2

5  
6 **Preamble:**

7 The Application states: *“The costing of external work is determined on the basis of cost causality,*  
8 *consistent with the costing of internal work, using the standard labour rates, equipment rates,*  
9 *material surcharge, and overhead rates. An appropriate margin is added to cover, at a minimum,*  
10 *market level pricing in order to ensure there is an overall benefit to transmission ratepayers”.*

11  
12 **Interrogatory:**

13 a) Please provide a schedule that for each of the years 2018-2023 sets out the “margin” (i.e., the  
14 revenues in excess costs) included in each category of External Revenues in Table 1.

15  
16 **Response:**

17 a) Please see below table which sets out the “margin” (i.e., the revenues in excess of costs) for  
18 each category of External Revenues for the years 2018 to 2023.

19

	Historical				Bridge	Forecast
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Secondary Land Use	Note 1					
Station Maintenance	1.7	1.5	1.4	0.5	0.5	0.5
Engineering & Construction	0.0	0.0	0.0	0.0	0.0	0.0
Other External Revenues	Note 1					

*Note 1: As outlined in Exhibit E-4-1, Hydro One does not directly track costs for all its unregulated service revenues, in particular for secondary land use and other external revenues. These costs are embedded in the company’s Common Corporate costs. The costing of external work is calculated the same way as for internal work and further described in Exhibit C-9-1 to C-9-4.*

20

Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
Schedule D-VECC-026  
Page 2 of 2

1

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Witness: SPENCER Andrew

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 027**

2  
3 **Reference:**

4 Exhibit D-2-1, Pages 3-4

5  
6 **Interrogatory:**

- 7 a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast  
8 Secondary Land Use External Revenue (per Table 2) for each year with the amounts  
9 approved for inclusion in rates over the same period.
- 10
- 11 b) At page 4 the Application states: "Hydro One has received or expects to receive \$4M in  
12 2020, \$23M in 2021, and \$9M in 2022 and 2023." Please confirm the amount actually  
13 received in 2020 and update the annual amounts expected for 2021-2022 as required.
- 14
- 15 c) The payments from Imperial Oil are characterized as the result of a "one time easement  
16 arrangement". For each of the years 2018-2022 what are the total revenues included in  
17 Table 2 for such arrangements and what are the forecast amounts included for each of the  
18 years 2023-2027?

19  
20 **Response:**

- 21 a) The following table outlines the 2018 to 2022 actual/forecast secondary land use external  
22 revenues (as per Table 2 of Exhibit D-2-1) compared to the OEB approved amounts.

23

Secondary Land Use Revenue (\$ Millions)	Historical				Bridge
	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Forecast	Forecast
Actual / Forecast <sup>1</sup>	25.6	27.7	29.1	46.5	28.8
OEB Approved	15.6	15.6	23.5	23.5	23.5

24 Note: the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.

- 25
- 26 b) The amount of \$4 million was received in 2020, \$23 million is forecast in 2021, and \$9  
27 million is forecast between 2022 and 2023.
- 28
- 29 c) The total combined forecast for the Imperial Oil payments on the Waterdown to Finch  
30 Pipeline project is approximately \$36 million between years 2020 and 2023. Hydro One

---

<sup>1</sup> Exhibit D-2-1, Table 2

1           received \$4 million in 2020, is forecast to receive \$23 million in 2021, and is forecast to  
2           receive an additional \$9 million between 2022 and 2023, as outlined in response to part (b)  
3           above. There are no other revenues forecast for the 2024 to 2027 period for this project.



1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 028**

2

3 **Reference:**

4 Exhibit D-2-1, Page 5

5

6 **Interrogatory:**

7 a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast  
 8 Station Maintenance External Revenues (per Table 3) for each year with the amounts  
 9 approved for inclusion in rates over the same period.

10

11 b) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast  
 12 Engineering and Construction External Revenues (per Table 4) for each year with the  
 13 amounts approved for inclusion in rates over the same period.

14

15 **Response:**

16 a) The following table outlines the 2018 to 2022 actual/forecast station maintenance external  
 17 revenues (as per Table 3 of Exhibit D-2-1), compared to the OEB approved amounts.

18

Station Maintenance (\$ Millions)	Historical				Bridge
	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Forecast	Forecast
Actual / Forecast <sup>1</sup>	4.6	4.0	3.5	3.4	3.4
OEB Approved	5.3	5.3	4.0	4.0	4.0

Note the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.

19

20 b) The following table outlines the 2018 to 2022 actual/forecast engineering and construction  
 21 external revenues (as per Table 4 of Exhibit D-2-1) compared to the OEB approved amounts.

22

Engineering & Construction (\$ Millions)	Historical				Bridge
	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Forecast	Forecast
Actual / Forecast <sup>2</sup>	0.1	0.1	0.2	0.4	0.4
OEB Approved	-	-	0.3	0.3	0.3

Note the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.

<sup>1</sup> Exhibit D-2-1, Table 3

<sup>2</sup> Exhibit D-2-1, Table 4

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1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 029**

2

3 **Reference:**

4 Exhibit D-2-1, Page-6  
5 EB-2019-0082, Exhibit 10, Schedule 20, part b)

6

7 **Interrogatory:**

8 a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast  
9 Other External Revenues (per Table 5) for each year with the amounts approved for  
10 inclusion in rates over the same period.

11

12 b) Please explain why Other External Revenues decrease annually from 2023-2026 and then  
13 increase in 2027.

14

15 c) Do the forecast Other External Revenues include revenues as a result of the vegetation  
16 management cycle planned to be completed for Bruce to Milton Limited Partnership every 6  
17 years? If yes, how much and in what years? If not, why not?

18

19 d) Do the actual/forecast Other External Revenues include revenues from the leasing of idle  
20 transmission lines? If not, why not? If yes, please provide a schedule of the annual  
21 actual/forecast revenues for 2018-2027.

22

23 e) Do the actual/forecast Other External Revenues include revenues from the by-pass charges?  
24 If not, why not? If yes, please provide a schedule of the annual actual/forecast revenues for  
25 2018-2027.

**Response:**

a) The following table outlines the 2018 to 2022 actual/forecast other external revenues (as per Table 5 of Exhibit D-2-1) compared to the OEB approved amounts.

Other External Revenues (\$ Millions)	Historical				Bridge
	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Forecast	Forecast
Actual / Forecast <sup>1</sup>	9.1	8.1	5.2	8.7	7.2
OEB Approved	7.6	7.6	9.2	10.3	9.4

Note the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.

b) Other External Revenues includes revenues from work completed by Hydro One Transmission on behalf of the Hydro One's affiliate companies. In particular, the Bruce to Milton LP vegetation management maintenance work which is cyclical in nature during the plan years is driving the fluctuations in this category.

c) Yes, Other External Revenues includes forecast revenues as a result of the vegetation management cycle planned to be completed for Bruce to Milton Limited Partnership as follows:

(\$ Millions)	2023	2024	2025	2026	2027
Bruce to Milton LP Vegetation Management Maintenance	0.86	0.34	0.30	0.06	0.74

d) Yes, Other External Revenues include revenues from the leasing of idle transmission lines, please see table below for the annual actual/forecast revenues for 2018 to 2027:

(\$ Millions)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Revenues from Leasing of Idle Transmission Lines	4.0	3.1	2.2	2.5	2.5	2.5	2.5	2.5	2.5	2.5

e) The actual/forecast does not include revenues from temporary by-pass charges due to the cessation of it with Toronto Hydro in 2018.

<sup>1</sup> Exhibit D-2-1, Table 5

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 030**

2  
3 **Reference:**

4 Exhibit D-2-2, Attachment 1, Pages 4-8

5  
6 **Interrogatory:**

- 7 a) Please provide a breakdown of Distribution Other Operating Revenue using the individual  
8 USOA accounts as set out in Appendix 2-H of the July 12, 2021 model.
- 9
- 10 b) With respect to the Appendix 2-H Table provided in Attachment 1, should the USOA  
11 reference for the first row be "4225/4235" as opposed to "4225/4325"?
- 12
- 13 c) With respect to the Appendix 2-H Table provided in Attachment 1, please explain why USOA  
14 4325 (Revenues from Merchandise Jobbing, Etc.) is used to record Regulated Revenues from  
15 Joint Use, Sentinel Lights, Other External Work and Distributor Generator Studies.
- 16
- 17 d) The Hydro One Networks does not appear to have included any revenue from Retail Service  
18 Charges – USOA #4082 & 4084 (per Exhibit L, Tab 7, Schedule 1, Attachment 1, page 17 of  
19 18). Please confirm whether or not this is the case.
- 20 i. If included, please indicate where and what the annual amounts are for 2018-2027
- 21 ii. If not included, please explain why.
- 22 iii. If not included and Hydro One receives such revenues, please provide the  
23 actual/forecast annual amounts for 2018-2022.
- 24 iv. If not included, does Hydro One have a forecast of what the expected annual amounts  
25 are for 2023-2027?
- 26

27 **Response:**

- 28 a) Please refer to Exhibit D-02-02 Attachment 1. In that Exhibit, Hydro One has completed  
29 Appendix 2-H identifying all of the External Revenue components offsetting the Distribution  
30 Revenue Requirement by the following line items: Regulated Revenue, Unregulated  
31 Revenue, Standard Supply Service Charge, MicroFIT Revenue and ST Local Transformation  
32 Charge. The Appendix was provided to align with the External Revenue Exhibit in the current  
33 application. Further breakdown of Regulated Revenue and Unregulated Revenue is detailed  
34 in Exhibit D-02-02. Please refer to Interrogatory Response D-VECC-032 for further details  
35 regarding Specific Service Charges.
- 36

- 1 b) The line item Retail Services Revenues – Regulated refers to a number of customer related  
2 administrative services as further described in Exhibit L-04-01 including late payment  
3 charges. Hydro One has captured these revenues in USofA 4325 and late payment charges in  
4 USofA 4225.  
5  
6 c) As it relates to Joint Use, Sentinel Lights, Other External Work and Distributor Generator  
7 Studies similar to the reason provided above, Hydro One has captured these revenues in  
8 USofA 4325.  
9  
10 d)  
11 i) Hydro One has included revenue from Retail Service Charges (i.e., charges to  
12 retailers of electricity as set out in Hydro One’s tariff filed at Exhibit L-07-01,  
13 Attachment 1, page 17). The revenue from Retail Service Charges forms part of the  
14 Retail Services Revenues – Regulated line item.  
15

\$M	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Revenue from Charges to Retailers	0.5	0.7	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6

- 16  
17 ii) Not applicable  
18  
19 iii) Not applicable  
20  
21 iv) Not applicable

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 031**

2

3 **Reference:**

4 Exhibit D-2-2, Pages 3 and 8

5 Exhibit D-2-1, Page 2

6

7 **Preamble:**

8 With respect to Distribution, the Application states: "For unregulated work, Hydro One adds an  
9 appropriate margin above its cost to cover, at a minimum, the risk of non-payment by third  
10 parties."

11

12 With respect to Transmission, the Application states: "An appropriate margin is added to cover,  
13 at a minimum, market level pricing in order to ensure there is an overall benefit to transmission  
14 ratepayers"

15

16 **Interrogatory:**

17 a) There appears to be a different basis for determining the margin for unregulated work under  
18 taken by the Transmission business as opposed to the Distribution business. Please clarify  
19 whether or not this is the case.

20 i. If yes, please explain why.

21 ii. If not, please clarify the common basis used to determine the margins for unregulated  
22 work.

23

24 **Response:**

25 a) There is not a different basis. For unregulated work Hydro One adds an appropriate margin  
26 to cover at a minimum, market level pricing in order to ensure there is an overall benefit to  
27 ratepayers; this considers the risk of non-payment by third parties.

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**D, L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY -  
 032**

**Reference:**

Exhibit D-2-2, Page 4  
 Exhibit L-4-1, Attachment 3

**Interrogatory:**

- a) Please provide a schedule that maps the Rate Codes listed in Exhibit L, Tab 4, Schedule 1, Attachment 3 to the five rows set out in Table 3 of Exhibit D, Tab 2, Schedule 2.
- b) Do the total revenues from all of the Rate Codes listed in Exhibit L, Tab 4, Schedule 1, Attachment 3 reconcile with the total revenues in Table 3? If not, please explain what accounts for any differences.
- c) Please provide a schedule that for each of the years 2018-2027 sets out the anticipated annual volume of activity and revenues from each Rate Code in Exhibit L, Tab 4, Schedule 1, Attachment 3.

**Response:**

a)

Rate Code	Rate Description	D-02-02 Table 3 Mapping
<b>Customer Administration</b>		
6a	Easement letter - letter request	Retail Service Revenues
6b	Easement letter - web request	Retail Service Revenues
11	Returned cheque charge	Retail Service Revenues
14	Account set up charge/change of occupancy charge (plus credit agency costs, if applicable)	Retail Service Revenues
15	Special meter reads (retailer requested off-cycle read)	Retail Service Revenues
24	Meter dispute charge plus Measurement Canada fees (if meter found correct)	Retail Service Revenues
<b>Non-Payment of Account</b>		
52	Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	Retail Service Revenues
18 & 19	Collection - reconnect at meter - during regular hours	Retail Service Revenues
20 & 21	Collection - reconnect at meter - after regular hours	Retail Service Revenues
22	Collection - reconnect at pole - during regular hours	Retail Service Revenues

Witness: LI Clement

23	Collection - reconnect at pole - after regular hours	Retail Service Revenues
<b>Other</b>		
25 <sup>1</sup>	Service call - customer owned equipment - during regular hours	Not Applicable
26 <sup>1</sup>	Service call - customer owned equipment - after regular hours	Not Applicable
32	Reconnect completed after regular hours (customer/contract driven) - at meter	Not Applicable
33	Reconnect completed after regular hours (customer/contract driven) - at pole	Not Applicable
34 & 35	Additional service layout fee - basic/complex (more than one hour)	Not Applicable <sup>2</sup>
36	Pipeline crossings	Not Applicable <sup>2</sup>
37	Water crossings	Not Applicable <sup>2</sup>
38	Railway crossings (additional Railway Feedthrough Costs apply)	Not Applicable <sup>2</sup>
39a	Overhead line staking per meter	Not Applicable <sup>2</sup>
39b	Underground line staking per meter	Not Applicable <sup>2</sup>
39c	Subcable line staking per meter	Not Applicable <sup>2</sup>
40	Central metering - new service <45 kw	Not Applicable <sup>2</sup>
41	Conversion to central metering <45 kw	Not Applicable <sup>2</sup>
42	Conversion to central metering >=45 kw	Not Applicable <sup>2</sup>
45a	Connection impact assessments - net metering	Distributor Generator Studies
45b	Connection impact assessments - embedded LDC generators	Distributor Generator Studies
45c	Connection impact assessments - small projects <= 500 kw	Distributor Generator Studies
45d	Connection impact assessments - small projects <= 500 kw, simplified	Distributor Generator Studies
45e	Connection impact assessments - greater than capacity allocation exempt projects - capacity allocation required projects	Distributor Generator Studies
45f	Connection impact assessments - greater than capacity allocation exempt projects - TS review for LDC capacity allocation required projects	Distributor Generator Studies
50	Sentinel light rental charge	Sentinel Light
51	Sentinel light pole rental charge	Sentinel Light
30	Specific charge for access to power poles - telecom	Joint Use
47	Specific charge for access to power poles - LDC	Joint Use
48	Specific charge for access to power poles - generators	Joint Use
49	Specific charge for access to power poles - municipal streetlights	Joint Use
<b>Specific Charge for LDCs Access to the Power Poles (\$/pole/year)</b>		
47	LDC rate for 10' of power space	Joint Use
47	LDC rate for 15' of power space	Joint Use
47	LDC rate for 20' of power space	Joint Use
47	LDC rate for 25' of power space	Joint Use
47	LDC rate for 30' of power space	Joint Use

47	LDC rate for 35' of power space	Joint Use
47	LDC rate for 40' of power space	Joint Use
47	LDC rate for 45' of power space	Joint Use
47	LDC rate for 50' of power space	Joint Use
47	LDC rate for 55' of power space	Joint Use
47	LDC rate for 60' of power space	Joint Use
<b>Specific Charge for Generator Access to the Power Poles (\$/pole/year)</b>		
48	Generator rate for 10' of power space	Joint Use
48	Generator rate for 15' of power space	Joint Use
48	Generator rate for 20' of power space	Joint Use
48	Generator rate for 25' of power space	Joint Use
48	Generator rate for 30' of power space	Joint Use
48	Generator rate for 35' of power space	Joint Use
48	Generator rate for 40' of power space	Joint Use
48	Generator rate for 45' of power space	Joint Use
48	Generator rate for 50' of power space	Joint Use
48	Generator rate for 55' of power space	Joint Use
48	Generator rate for 60' of power space	Joint Use

*Note 1: Base Charge only. Additional work on equipment will be based on actual costs.*

*Note 2: The rate codes that are not mapped to D-02-02 Table 3 are Capital Contribution and do not contribute to external revenue.*

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2  
3  
4  
5  
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8  
9  
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11  
12

- b) The Rate Codes listed in Exhibit L, Tab 4, Schedule 1, Attachment 3 (“SSCs”) are for specific services with an approved fixed charge. The total revenue in Table 3 of Exhibit D, Tab 2, Schedule 2 (“Regulated External Revenue”) does not reconcile with the total revenues from all of the SSCs for the following reasons: i) the SSCs that map to contributed capital are not considered external revenue; ii) revenues from Retailer Service charges contribute to the Retail Service Revenues in Regulated External Revenue and are not SSCs and; iii) SSCs do not include Regulated External Revenues for services where variable charges apply, which includes revenues from Other External Work.
- c) Please see Attachment 1 for anticipated annual revenues. Please note that not all specific service charges/Rate Codes were forecasted on a separate basis.

Witness: LI Clement

Filed: 2021-11-29  
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Tab 24  
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Witness: LI Clement

Rate Code	Rate Description	Revenues (\$ Million)										Volumes									
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
6a & 6b	Easement Letters (letter and web request)	\$0.06	\$0.05	\$0.04	\$0.28	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10										
11	Returned cheque charge	\$0.14	\$0.10	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	9,738	14,325	7,980	7,740	7,508	7,283	7,064	6,853	6,647	6,448
14	Account set up charge/change of occupancy charge (plus credit agency costs, if applicable)	\$2.51	\$1.55	\$1.37	\$1.49	\$1.43	\$1.38	\$1.33	\$1.29	\$1.24	\$1.20	67,407	41,610	22,605	39,158	37,759	36,409	35,107	33,852	32,642	31,475
52	Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	\$10.90	\$11.97	\$2.74	\$10.75	\$10.85	\$10.96	\$11.07	\$11.18	\$11.29	\$11.41										
18 to 23	Collections - Reconnect	\$0.66	\$0.23	-\$0.08	\$0.66	\$1.12	\$1.13	\$1.14	\$1.15	\$1.16	\$1.17										
45	Connection impact assessments	\$2.80	\$0.80	\$0.30	\$0.50	\$0.50	\$0.50	\$0.50	\$0.50	\$0.50	\$0.50										
50 & 51	Sentinel Light (rental charge and pole rental charge)	\$3.00	\$3.00	\$3.00	\$2.82	\$2.70	\$2.59	\$2.49	\$2.39	\$2.30	\$2.20										
30	Specific charge for access to power poles - telecom	\$12.24	\$13.06	\$13.44	\$13.32	\$13.60	\$14.20	\$14.24	\$14.28	\$14.32	\$14.36	303,172	303,300	305,270	303,454	303,912	316,944	317,551	318,160	318,770	319,382
47	Specific charge for access to power poles - LDC	\$0.48	\$0.71	\$0.85	\$0.90	\$0.89	\$0.91	\$0.91	\$0.91	\$0.91	\$0.91	10,184	10,154	10,143	10,165	9,994	9,999	10,004	10,009	10,014	10,019
48	Specific charge for access to power poles - generators	\$0.24	\$0.44	\$0.45	\$0.45	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	4,123	4,123	4,123	4,123	4,123	4,123	4,123	4,123	4,123	4,123
49	Specific charge for access to power poles - municipal streetlights	\$0.17	\$0.17	\$0.17	\$0.17	\$0.17	\$0.17	\$0.17	\$0.17	\$0.17	\$0.17	82,825	82,825	82,825	82,825	82,825	82,825	82,825	82,825	82,825	82,825

**Notes:**

Rate code 15: Hydro One does not charge customers for off-cycle reads. Hydro One waits for an on-cycle read to occur, in the rare event that a retailer requests an off-cycle read.

Rate code 24: The meter dispute fee is not included in forecasts due to the fact that it is rarely charged (approximately 5 times per year).

Rate codes 25 and 26: Hydro One waives these fees for all customers due to safety concerns.

Rate codes 32 and 33: This charge was not included in forecasts as it was implemented after the forecast was completed. This charge is expected to result in an immaterial amount of revenue.

Rate codes 34 to 42: These are Capital Contributions which do not contribute to external revenues

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 033**

2

3 **Reference:**

4 Exhibit D-2-2, Page 4

5

6 **Interrogatory:**

7 a) Is all of the year over year decline in Retail Services Revenue (2023-2027) shown in Table 4  
8 due to the expected decline in new account set up requests completed via the call center? If  
9 not, what else accounts for the decline?

10

11 **Response:**

12 a) The year over year decline in Retail Services Revenue (2023-2027) is due to the expected  
13 decline in new account set up requests completed via the call center and retailer services. A  
14 different focus in customer programs is also expected to generate less revenue.

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Exhibit I  
Tab 24  
Schedule D-VECC-033  
Page 2 of 2

1

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Witness: GILL Spencer

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 034**

2  
3 **Reference:**

4 Exhibit D-2-2, Page 10

5  
6 **Interrogatory:**

7 a) Are the historical Storm Revenues shown in Table 12 net of any costs incurred by Hydro One  
8 Networks to help other utilities affected by major power outages? If the amounts are gross  
9 revenues, what were the net revenues after accounting for the associated costs?

10  
11 b) The Application states that “these instances are unpredictable and dependent on Hydro One’s  
12 ability to deploy storm relief outside jurisdictions and, accordingly, are not forecast”. Would  
13 Hydro One Networks be open to establishing a variance account to record net Storm  
14 Revenues over the 2023-2027 period and to subsequently refunding the amounts to  
15 customers? If not, why not?

16  
17 **Response:**

18 a) The revenues in Table 12 of exhibit D-2-2 are gross revenues. The net revenues are \$0 as we  
19 do not make a profit on mutual assistance programs and only bill the customer for cost  
20 recovery.

21  
22 b) Hydro One is not considering a variance account at this time; the Company will manage the  
23 variances related to storm relief efforts.



Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
Schedule D-VECC-034  
Page 2 of 2

1

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Witness: NG Chong Kiat

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 035**

2  
3 **Reference:**

4 Exhibit D-3-1

5 Exhibit D-3-1, Attachment 1

6  
7 **Preamble:**

8 D-3-1, page 1 states: "The load forecasts in support of this Application were prepared in February  
9 2021, using the economic and forecast information then available".

10  
11 **Interrogatory:**

12 a) With respect to the Tabs in Attachment 1, is data shown for years up to and including 2020  
13 all based on actual values while the data for 2021 and subsequent years is all based on  
14 forecast? If not, for each Tab, please indicate where the basis of the data is different from  
15 that posited in the previous sentence.

16  
17 b) For each of the Tabs in Attachment 1, please indicate the sources for the historical data.  
18 Similarly, please provide the source for the annual Housing Start values set out in Exhibit D,  
19 Tab 5, Schedule 1.

20  
21 c) With respect to the following forecast values in Attachment 1:

- 22 • Broad Annual Series Tab: Please explain the basis for the forecasts for Ontario  
23 Population, Ontario Disposable Income, Ontario Commercial GDP and Ontario  
24 Industrial GDP. As part of the response please explain how the forecasts for  
25 Commercial GDP and Industrial GDP are made consistent with consensus forecast of  
26 Ontario GDP (per D/4/1, pages 30 & 32).
- 27  
28 • Monthly Building Permits Tab values. Please explain how the forecast was derived  
29 from the forecast of housing starts (per D/4/1, Appendix A)
- 30  
31 • Monthly GDP Tab values. Please explain how the forecast was derived from the  
32 annual GDP forecast in the Broad Annual Series Tab (per D/4/1, Appendix A).
- 33  
34 • Physical Production Unit Tab values for each sector. Again, as part of this response  
35 please indicate how the forecast for physical production units by sector is related to  
36 the forecast of Ontario Industrial GDP (as set out in the Broad Annual Series Tab).

- 1           • Floor Space Tab values. Please explain how the forecast values for the individual  
2           sectors were derived.  
3  
4           • GDP Components Tab values. Please explain how the forecasts for the individual  
5           sectors were derived. As part of this response please indicate how the GDP  
6           Components forecast is consistent with the forecast of Annual GDP (as set out in the  
7           Broad Annual Series Tab).  
8  
9   d) Exhibit D, Tab 4, Schedule1, page 28 states that the forecast number of households is based  
10       on the consensus forecast of housing starts. However, for the forecast period, the year over  
11       year change in housings stock (per Attachment 1, Broad Annual Series Tab) does not equal  
12       (i.e., is less than) the annual Housing Starts forecast (per D/3/1, Appendix A). Please explain  
13       why and, as part of the response, provide a schedule that reconciles/explain the differences  
14       between the two.  
15  
16   e) With respect to D/3/1, Appendix A - please explain why, when the load forecast was prepared  
17       in February 2021 some of the forecasts for the inputs used date as early as January 2020. How  
18       dated would an input forecast source need to be before Hydro One would consider it too “old”  
19       to use in determining the consensus forecast.  
20  
21   f) Please provide an update to D/3/1, Appendix A incorporating any more recent forecasts  
22       prepared by the sources cited.  
23

24   **Response:**

- 25   a) For all tabs in Attachment 1, for all annual figures, last actual value available at the time of  
26       forecast (Feb 2021) was for the year 2019 except for heating and cooling degree days and  
27       Ontario population, which were available for 2020.  
28  
29       Actual monthly figures for building permits were available for up to December 2020 and for  
30       monthly GDP, third quarter of 2020.  
31  
32   b) For source of historical data, including for Housing Starts, please see Appendix A and B of  
33       Exhibits D-4-1 and D-5-1.  
34  
35   c)  
36       • For the source of Ontario disposable income and population forecast please see Exhibit  
37       D-4-1 Appendix B. Forecast of commercial GDP and Industrial GDP were derived from  
38       forecast of corresponding GDP forecast by sector from IHS Global Insight, adjusted for the

1 difference between Ontario GDP growth consensus forecast in Appendix to Exhibit D-3-1  
2 and that for IHS Global Insight.

3

4 • The annual values of building permits are calculated by applying the growth rate of  
5 housing starts. The annual values are then multiplied by the monthly pattern of building  
6 permits which is derived from the average monthly profile of building permits in the last  
7 3 years.

8

9 • First Quarterly GDP values were forecast from growth rate of quarterly GDP forecast from  
10 IHS Global Insight, when available. The quarterly forecasts were scaled to have the same  
11 annual growth rate as the annual forecast from the appendix in Exhibit D-3-1. When  
12 quarterly GDP forecast from IHS Global Insight ends, the annual growth rate from the  
13 appendix in Exhibit D-3-1 are applied to corresponding quarterly values. Finally, quarterly  
14 values are scaled by monthly pattern in each quarter to arrive at monthly GDP. The latter  
15 pattern was developed internally based on expected business activity in each month.

16

17 • Physical production unit was developed by using an econometric model for each segment.  
18 Consistency with overall industrial activity, as measured by industrial GDP, was  
19 maintained through scaling the forecasts.

20

21 • Similarly, floor space forecast for each segment was developed using an econometric  
22 model for that segment and then the results were scaled to maintain consistency  
23 between floor space forecast and commercial GDP.

24

25 • Consistent with the derivation of industrial and commercial GDP noted above, forecast of  
26 the individual sectors were derived from corresponding GDP forecast by sector from IHS  
27 Global Insight, adjusted for the difference between Ontario GDP growth consensus  
28 forecast in Appendix to Exhibit D-3-1 and that for IHS Global Insight.

29

30 d) The description was at a high level. The forecast of number of households also accounts for  
31 depreciation/demolitions. Another factor involved is related to differences in timing of  
32 housing starts and when a house is completed. Relation between completion and housing  
33 starts were established by historical relationship between completion and, current and lagged  
34 value of housing starts. This yields completion as a weighted sum of current housing starts  
35 and its value lagged one year.

1 To put these two together:

2

3 Number of houses = (Number of houses lagged one year) \* (1 – depreciation/demolition  
4 rate/100) + weighted sum of current housing starts and its value lagged one year.

5

6 As such, the change in the number of houses cannot be equal to housing starts.

7

8 e) For every source, the latest available information was used, following same methodology as  
9 in previous rate fillings.

10

11 f) Please see response to D-LPMA-015.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 036**

2  
3 **Reference:**

4 Exhibit D-4-1, Pages 4-5

5 EB-2019-0082, Exhibit I-10-24

6 EB-2019-0082, Exhibit JT2.34, Question 11c

7  
8 **Preamble:**

9 The Application states (page 5): "Table 2 summarizes the CDM peak impacts assumed in Hydro  
10 One Transmission's system load forecast for 2006 to 2027."

11  
12 **Interrogatory:**

13 a) With respect to Table 2, for what years are the Cumulative CDM Impact on Peak Demand  
14 values actual vs. forecast?

15  
16 b) Please provide breakdown of the Cumulative CDM Impact on Peak Demand as between  
17 Energy Efficiency Programs and Codes & Standards for each of the years 2006-2027.

18  
19 c) Please confirm that the values for the years 2006-2018 are taken from the 2013 LTEP (as the  
20 values in Table 2 match those in the 2013 LTEP per EB-2019-0082, Exhibit I, Tab 10, Schedule  
21 24)?

22  
23 d) Are the values in Table 2 measured at point of delivery (end-use) or point of generation? The  
24 footnote suggests that it is point of delivery. However, in the response to Exhibit JT2.34, Q  
25 11 c) the generation level values match those in Table 2.

26  
27 e) It is noted that the Application refers to the values for the historical years as being "assumed"  
28 values (page 5, line 1)? What is the basis for assuming that the actual values for the years  
29 2013-2018 are the same as the forecast values in the 2013 LTEP (e.g., is Hydro One Networks  
30 aware of any "after the fact" analysis that would verify this assumption)?

31  
32 f) Between 2013 and 2018 did the IESO (or the former OPA) provide any updates/revisions to  
33 the actual or forecast MW CDM savings for the years prior to 2019 (e.g., in its Annual Planning  
34 Outlooks) that differed from the CDM savings for 2013-2018 in the 2013 LTEP? If yes, why  
35 weren't these values used instead?

1 g) Between 2013 and 2018 did the IESO (or the former OPA) provide any updates/revisions to  
 2 either the actual or forecast MWH CDM savings for the year prior to 2019 (e.g., in its Annual  
 3 Planning Outlooks) that differed from the CDM MWh savings in the 2013 LTEP? If yes, why  
 4 weren't the CDM MW savings for 2013-2018 adjusted to reflect this change, assuming a  
 5 change in MWh savings would result in a change in MW savings?  
 6

7 **Response:**

8 a) The 2006-2019 CDM peak savings is the "estimated" actual from the IESO. Due to data  
 9 availability issues from IESO, the historical CDM impact can only be "estimated" but not  
 10 "verified".  
 11

12 b) Hydro One does not have the breakdown of EE and C&S for the peak impact for 2019-2027.  
 13

Year	Energy Efficiency (EE)	Code and Standards (C&S)	Total cumulative CDM impact on Peak Demand *
2006	289	0	289
2007	760	18	778
2008	853	40	893
2009	930	67	997
2010	1,060	107	1,167
2011	1,034	284	1,318
2012	1,141	329	1,470
2013	1,248	373	1,621
2014	1,435	386	1,821
2015	1,528	413	1,941
2016	1,662	505	2,167
2017	1,575	525	2,100
2018	1,752	639	2,391
2019			2,511
2020			2,493
2021			2,544
2022			2,609
2023			2,682
2024			2,667
2025			2,691
2026			2,725
2027			2,802

\* The figure represent the load impact of CDM on summer peaks

- 1 c) Confirmed.  
2  
3 d) The values in Table 2 noted above are measured at generation level.  
4  
5 e) Hydro One is not aware of any official “after the fact” analysis on 2013-2018 peak savings for  
6 all EE and C&S programs from the IESO.  
7  
8 f) No, there is no updated CDM peak (MW) savings for 2013-2018 from the IESO.  
9  
10 g) Yes, the APO 2020 provided the updated CDM energy MWH savings, however the difference  
11 between 2015-2018 energy savings (TWh) used in Hydro One’s load forecast and the APO  
12 2020 is insignificant as shown in the table below.  
13

	2015	2016	2017	2018	2019
OPO2020	13.97	15.03	17.24	19.34	19.48
Energy savings used in load forecasting	13.93	15.55	17.27	19.31	19.41



Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
Schedule D-VECC-036  
Page 4 of 4

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Witness: ALAGHEBAND Bijan

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 037**

2  
3 **Reference:**

4 Exhibit D-4-1, Pages 4-5  
5 EB-2019-0082, Exhibit I-10-25  
6

7 **Preamble:**

8 The Schedule states: "Hydro One derived monthly CDM savings using IESO's (formerly the OPA's)  
9 hourly load shape. The annual peak savings (July) is applied to the monthly saving profile to derive  
10 the monthly peak savings, and 12-month average peak savings, for the actual and forecast  
11 periods."  
12

13 **Interrogatory:**

- 14 a) Please clarify whether the hourly load shape used was an hourly load shape for CDM savings  
15 or for the overall system load.  
16  
17 b) If it was an hourly load shape for CDM savings, was the load shape used for the historical years  
18 revised every year to reflect the new CDM savings achieved each year?  
19  
20 c) If it was an hourly load shape for CDM savings, what was the basis for the load shape used for  
21 the forecast years?  
22  
23 d) If it was a system load shape, was the load shape used for each historical year revised based  
24 on that year's actual load profile?  
25  
26 e) If it was a system load shape, what was the basis for the load shape used for the forecast  
27 years?  
28

29 **Response:**

- 30 a) The hourly load shape used was an hourly load shape for CDM savings.  
31  
32 b) The hourly load shape for CDM savings was the load shape for each year including historical  
33 and forecasting periods.  
34  
35 c) See response to b).  
36  
37 d) See response to b).

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- 1 e) See response to b).

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 038**

2  
3 **Reference:**

4 Exhibit D-4-1, Pages 4-5  
5 EB-2019-0082, Exhibit I-10-24  
6

7 **Preamble:**

8 The Application states (page 4): "Hydro One has used the 2013 LTEP assumptions and taken into  
9 account the IESO's latest province-wide conservation forecast to establish the CDM impacts in the  
10 load forecast. Hydro One adopted two CDM categories that are consistent with the IESO's (then  
11 the OPA) 2013 LTEP information: energy efficiency programs and codes and standards. Details of  
12 the latest information that was provided in February 2021 by the IESO, which are consistent with  
13 the IESO's latest Annual Planning Outlook APO), and the methodology used by Hydro One to  
14 derive the CDM impacts for the three charge determinants, have been documented in sections  
15 3.1 and 4.0 of this exhibit."  
16

17 **Interrogatory:**

- 18 a) Did the 2013 LTEP forecast CDM MW savings for any of the years after 2022. If yes, please  
19 provide the forecast savings from energy efficiency programs and code & standards  
20 (separately). Please also provide a copy of the source reference.  
21
- 22 b) It is noted that the CDM savings set out in Table 2 for the years after 2018 differ from those  
23 in the 2013 LTEP. Please describe how the savings from i) energy efficiency programs and ii)  
24 codes and standards were determined for each of the years 2019-2027 and provide copies of  
25 any relevant sources/references used.  
26
- 27 c) If not included in the response to part (b), please demonstrate that the forecast values in  
28 Table 2 are consistent with the IESO's CDM demand savings targets for the Interim (CDM)  
29 Framework and the 2021-2024 CDM Framework.  
30
- 31 d) What was the nature of the "latest information that was provided in February 2021 by the  
32 IESO"? Please provide copies of any correspondence or reports received.  
33
- 34 e) What information from the latest IESO APO is the forecast consistent with and which IESO  
35 APO is the Application referring to?

**Response:**

a) Yes. The requested information is provided below:

Peak Demand Reduction Associated with Energy Savings Targets

Peak Demand Saving (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EE (historical and future programs)	1248	1435	1528	1662	1575	1752	2022	2321	2357	2470	2636	2865	2985	3125	3224	3378	3444	3556	3720	3880
Codes and Standards (existing and forecast)	373	386	413	505	525	639	777	876	984	1039	1056	1128	1176	1244	1398	1537	1647	1768	1879	1988
Total	1621	1820	1942	2167	2099	2391	2799	3197	3341	3509	3693	3993	4160	4369	4622	4915	5091	5324	5599	5868

b) The 2019-2027 Peak savings are derived based on the information from the IESO in Feb 2021 and 2013 LTEP data.

Step 1: The EE peak savings for 2019-2027 is provided by the IESO in Feb 2021.

Peak Demand Reduction Associated with Energy Savings Targets

Peak Demand Saving (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EE (historical and future programs)	1248	1435	1528	1662	1575	1752	2022	2321	2357	2470	2636	2865	2985	3125	3224	3378	3444	3556	3720	3880
Codes and Standards (existing and forecast)	373	386	413	505	525	639	777	876	984	1039	1056	1128	1176	1244	1398	1537	1647	1768	1879	1988
Total	1621	1820	1942	2167	2099	2391	2799	3197	3341	3509	3693	3993	4160	4369	4622	4915	5091	5324	5599	5868

The following table is the EE summer peak saving from the IESO in February 2021. The C&S savings are not included.

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Summer peak savings (IESO Feb 2021)	2,511	2,493	2,544	2,609	2,683	2,667	2,581	2,469	2,273 (1)
Incremental savings							(86)	(112)	(199)

Step 2: To construct a consistent data set required for Load forecasting purposes, Hydro One added C&S savings for 2025-2027 based on the 2013 LTEP. The incremental C&S savings in 2027 vs 2024 is 270 MW based on the 2013 LTEP. The judgement was used for the adjustment of C&S to make sure the incremental peak savings is similar to that for the 2021-2024 CDM framework period (175MW).

	2019	2020	2021	2022	2023	2024	2025	2026	2027
EE (historical and future programs)	2022	2321	2357	2470	2636	2865	2985	3125	3224
Codes and Standards (existing and forecast)	777	876	984	1,039	1,056	1,128	1,176	1,244	1,398 (2)
Total	2,799	3,197	3,341	3,509	3,693	3,993	4,160	4,369	4,622
C&S incremental savings						48	68	154 (3)=incremental of (2)	

Step 3: We added half of the C&S incremental savings to derive the savings for 2025-2027.

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Summer peak savings (IESO Feb 2021)	2,511	2,493	2,544	2,609	2,683	2,667	2,581	2,469	2,273 (1)
Adjustment (50% of incremental C&S)							24	34	77 (4)=50%
Peak savings used in the load forecast	2,511	2,493	2,544	2,609	2,683	2,667	2,605	2,503	2,350 (5)=(1)+(4)

- 1 c) The forecast values in Table 2 include savings from all historical and future EE programs. The
- 2 saving targets for the 2019-2020 Interim CDM Framework and the 2021-2024 Framework are
- 3 part of the total EE savings shown.
- 4
- 5 d) Please see the Excel table provided as I-24-D-VECC-038-01 to this Exhibit.
- 6
- 7 e) The application is referring to the 2020 APO.

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1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 039**

2  
3 **Reference:**

4 Exhibit D-4-1, Page 6

5  
6 **Interrogatory:**

7 a) What does Hydro One Networks include in “Embedded Generation”? For example, does it  
8 only include generators over a certain size and does it include both embedded generation  
9 sold to local distributors (e.g., MicroFIT and FIT) and behind the meter generation?

10  
11 b) Does the forecast for either CDM or Embedded Generation include any impacts due to Energy  
12 Storage? If so, what are the annual values?

13  
14 c) Does the forecast for either CDM or Embedded Generation include any impacts due to System  
15 By-Pass? If so, what are the annual values?

16  
17 **Response:**

18 a) “Embedded retail generator” means a customer that: (a) is not a wholesale market participant  
19 or a net metered generator (as defined in section 6.7.1 in the Distribution System Code); (b)  
20 owns or operates an embedded generation facility, other than an emergency backup  
21 generation facility; and (c) sells output from the embedded generation facility to the Ontario  
22 Power Authority under contract or to a distributor. Behind the meter (BTM) generation is not  
23 included.

24  
25 b) If the energy storage meets the above definition, then it is part of embedded generation. The  
26 IESO provides embedded generation information by generation type (wind, hydro, solar etc.);  
27 impacts from energy storage are included in the “OTHER” category. Hydro One does not have  
28 energy storage information for other LDCs. As for Hydro One Distribution, there are 29 energy  
29 storage facilities with the capacity of 70MW as of 2020.

30  
31 c) Embedded generation in the load forecast does not include non-injecting load displacement.



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1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 040**

2  
3 **Reference:**

4 Exhibit D-4-1, Pages 6 and 11

5 Exhibit D-4-1, Appendix A

6  
7 **Preamble:**

8 The Application states: "The load impacts of CDM and embedded generation are added back to  
9 the historical data set during the modelling process."

10  
11 **Interrogatory:**

12 a) What historical months/years were used to estimate the Monthly Econometric Model?

13  
14 b) What are the annual values for the load impact of CDM added back to the historical data set?

15  
16 c) What was the basis for the annual CDM (energy) impacts added back to the historical data  
17 set? In responding, please indicate whether the historical amounts added back are consistent  
18 with the verified CDM results reported by the IESO.

19  
20 d) What types of embedded generation were added back to the historical data and does the  
21 definition match that used for Embedded Generation in the Application (page 6)?

22  
23 e) What were the annual load impacts for embedded generation that were added back in each  
24 of the historical years?

25  
26 f) What is the Monthly Econometric Model's predicted annual energy use (before any  
27 deductions for CDM or Embedded Generation) for the last year for which 12 months of  
28 historical data was available? (Note: Predicted values would be the model's prediction for those  
29 years where the actual results were known)? How does this value compare with the actual  
30 annual energy use in the same year?

31  
32 g) What is the Monthly Econometric Model's predicted annual energy use for each of the  
33 subsequent years (before any deductions for CDM or Embedded Generation)?

34  
35 h) Are the forecast values from the Monthly Econometric Model based on energy use measured  
36 at point of generation or at the point delivery to the customer?

1 **Response:**

2 a) From Jan 1970 to Jan 2021.

3

4 b) The annual values are presented in the following table.

5

Year	GWh
2006	1,750
2007	3,829
2008	4,376
2009	5,360
2010	5,907
2011	7,302
2012	8,601
2013	9,686
2014	12,296
2015	13,925
2016	15,555
2017	17,273
2018	19,311
2019	19,414
2020	19,672
2021	20,857

6

7 c) The annual values were arrived at after consultation with IESO for use in forecasting load. The  
8 basis for the data is summarized in part c) of VECC-57.

9

10 d) The embedded generation matches that described in the Application (page 6) and includes:  
11 Solar, Wind, Water, Bio, Cogeneration. For more details, see Hydro One's response to Energy  
12 Probe-57, part b).

1 e) The annual embedded generation numbers are presented in the following table.

2

Year	GWh
2007	802
2008	1,087
2009	1,797
2010	3,034
2011	3,652
2012	4,131
2013	4,651
2014	5,315
2015	6,035
2016	6,635
2017	7,028
2018	7,270
2019	7,361
2020	7,612
2021	8,046

3

4 f) The requested information is not available from State-Space software. However, an R-  
5 squared of 0.994 and D.W. Statistic of 1.8 indicate that the predicted values were close to  
6 actual values.

7

8 g) The Monthly Econometric Model's predicted values, gross of CDM and Embedded generation,  
9 are presented in the following table.

10

Year	GWh
2021	160,814
2022	160,720
2023	161,762

11

12 h) They are based on energy use at the point of generation.

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1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 041**

2  
3 **Reference:**

4 Exhibit D-4-1, Pages 3-11

5 Exhibit D-4-1, Appendix B

6  
7 **Preamble:**

8 For each of the sectors, Appendix B (pages 27, 30, 32, 36 and 37) states that the impact of CDM  
9 has been included.

10  
11 **Interrogatory:**

- 12 a) What historical years were used to estimate the Annual Econometric Model?
- 13
- 14 b) What are the annual values for the load impact of CDM added back to the historical data set?  
15 For each year, please provide a breakdown as between Residential, Commercial, Industrial,  
16 Agricultural and Transportation.
- 17
- 18 c) What was the basis for the annual CDM (energy) impacts added back to the historical data  
19 set? In responding, please indicate whether the historical amounts added back are consistent  
20 with the verified CDM results reported by the IESO.
- 21
- 22 d) There is no reference to the impact of embedded generation being added back to the energy  
23 use for the Commercial and Industrial sectors. How was the impact of embedded (behind the  
24 meter) generation accounted for in the modelling of Commercial and Industrial Use?
- 25
- 26 e) Given the Annual Econometric Model is sectoral (i.e., Residential, Commercial, etc.), how does  
27 the modelling account for the impact of embedded generation that is sold directly to local  
28 distributors?
- 29
- 30 f) What is the Annual Econometric Model's predicted annual energy use (before any deductions  
31 for CDM or Embedded Generation) for the last year for historical data was available? How  
32 does this compare with the actual annual energy use in the same year?
- 33
- 34 g) What is the Annual Econometric Model's predicted annual energy use for each of the  
35 subsequent years (before any deductions for CDM or Embedded Generation)?
- 36

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1 h) Please confirm that the historical and forecast energy use values per the Annual Econometric  
2 Model are measured at the point of use by customers.

3  
4 **Response:**

5 a) The answer for each sector follows:

6  
7 Residential and Industrial: 1962-2019  
8 Agriculture and Transportation: 1981-2019  
9 Commercial: 1963-2019

10  
11 b) The CDM impact by sector is presented in the following table.

12

Year	Residential	Commercial	Agriculture	Transportation	Industrial
2006	1,147	385	3	1	64
2007	1,704	1,124	28	9	634
2008	1,949	1,386	31	11	624
2009	2,211	1,923	41	12	713
2010	2,185	2,497	41	12	664
2011	2,671	3,208	43	14	764
2012	3,119	3,689	57	11	1,025
2013	3,463	4,129	70	13	1,225
2014	4,363	5,334	89	19	1,495
2015	4,491	6,233	122	26	1,927
2016	4,833	6,983	143	31	2,310
2017	5,053	7,750	174	39	2,884
2018	5,286	8,567	216	48	3,683
2019	5,142	8,659	256	53	3,789

13  
14  
15 c) The annual values presented in part b) were arrived at after consultation with IESO for use in  
16 forecasting load. The basis for the data is summarized in part c) of VECC-57.

17  
18 d) The energy figures by sector are at end-use level. Consequently, the figures are not affected  
19 by embedded generation. In other words, they measure usage no matter who is the supplier.  
20 The same applies to industrial and commercial users.

21  
22 e) Please see the response to part d).

1 f) The predicted values for the year 2019 are presented in the following table.  
2

Sector	Actual	Predicted
Commercial	61942	61301
Residential	45524	45153
Industrial	42717	43631
Agriculture	2885	2836
Transprtation	598	608

3  
4  
5  
6  
7

g) The predicted values, gross of CDM, over the subsequent years are presented in the following table.

Year	Residential	Commercial	Agriculture	Transportation	Industrial
2020	45,076	62,297	2,879	607	51,307
2021	44,654	62,470	2,889	617	53,855
2022	44,147	62,868	2,966	626	54,284
2023	43,762	63,458	2,818	634	53,654
2024	43,492	64,125	2,805	639	52,564
2025	43,284	64,879	2,809	643	51,436
2026	43,123	65,708	2,793	646	50,467
2027	42,985	66,576	2,770	649	49,281

8  
9  
10

h) Confirmed.



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1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 042**

2  
3 **Reference:**

4 Exhibit D-4-1, Page 13  
5 Exhibit D-4-1, Appendix C  
6

7 **Preamble:**

8 The Application states (page 13): “the resulting forecast is gross of the load impact of CDM and  
9 embedded generation”.

10  
11 **Interrogatory:**

- 12 a) What is the base year used for the End Use Model?  
13  
14 b) What is the CDM impact for each sector that was included in (added back to) the base year  
15 energy use?  
16  
17 c) What is the embedded generation impact for each sector that was included in (added back  
18 to) the base year energy use for each sector?  
19  
20 d) Given the End Use Model is sectoral (i.e., Residential, Commercial, etc.), how does the  
21 modelling account for the impact of embedded generation that is sold directly to local  
22 distributors?  
23  
24 e) What is the End Use Energy Model’s predicted annual energy use (before any deductions for  
25 CDM or Embedded Generation) for the base year? How does this compare with the actual  
26 energy use for the year?  
27  
28 f) What is the End Use Energy Model’s predicted annual energy use for each of the subsequent  
29 years (before any deductions for CDM or Embedded Generation)?  
30  
31 g) Please confirm that the historical and forecast energy use values per the End Use Model are  
32 measured at the point of use by customers.

1 **Response:**

- 2 a) 2020.
- 3
- 4 b) For the End-use model we don't need to add-back CDM to actual values. The forecast is gross  
5 of incremental CDM over the forecast period.
- 6
- 7 c) Please see response to D -VECC -41, part d).
- 8
- 9 d) Please see response to D -VECC -41, part d).
- 10
- 11 e) This information is not available for the base year due to the nature of the End-use model.
- 12
- 13 f) The requested information is provided in the following table, representing the forecast gross  
14 of incremental CDM.

15

Year	Residential	Commercial	Agriculture	Transportation	Industrial
2020	39,934	53,637	2,623	554	47,519
2021	40,061	53,808	2,632	556	47,670
2022	40,129	53,899	2,631	555	47,750
2023	40,065	53,813	2,622	554	47,770
2024	40,042	53,778	2,615	552	47,829
2025	40,022	53,749	2,609	551	47,841
2026	39,980	53,724	2,602	550	47,782
2027	39,949	53,695	2,596	548	47,733

- 16
- 17
- 18 g) Confirmed.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 043**

2  
3 **Reference:**

4 Exhibit D-4-1, Page 6 and 16-18  
5 Exhibit D-4-1, Appendix G  
6 EB-2016-0160, Exhibit I-12-25  
7

8 **Preamble:**

9 The Application states (page 6): “The forecast base year is corrected for abnormal weather  
10 conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized  
11 base year value”.

12  
13 The Application states (page 16): “Table 3 presents the forecast prepared for this application  
14 before and after deducting the load impacts attributed to embedded generation and CDM for the  
15 period 2019 to 2027”.

16  
17 The Application states (page 16): “Appendix D to this Exhibit provides the historical actual and  
18 weather-corrected charge determinant data for years 2008 to 2020”  
19

20 **Interrogatory:**

21 a) The graph on page 6 and the second quote referenced above from page 16 suggest that the  
22 base year for the forecast was 2020. However, the first quote referenced above from page  
23 16 suggests that it was 2018 (i.e., 2019 is part of the forecast period). Please clarify what the  
24 base year was to which the forecast growth rates were applied. As part of the response please  
25 confirm that the values for the base year to which the growth rates were applied are actual  
26 weather normalized values.  
27

28 b) With respect to both Table 3 and Appendix G, please indicate for which years are the values  
29 provided actual results vs. forecast.  
30

31 c) Please provide a schedule that sets out the forecast growth rates from each of the three  
32 models and the forecast growth rates that were used for to determine the forecast values for  
33 each year after the base year.  
34

35 d) Please confirm that the methodology for forecast the Charge Determinants is the same as  
36 that described in EB-2016-0160: “the Ontario peak growth rates, prior to Embedded  
37 Generation and CDM deductions, were applied to the 2015 charge determinants. Then the

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1 corresponding Embedded Generation and CDM impacts were deducted to arrive at charge  
2 determinants net of those impacts.” If not confirmed what is the approach used in the  
3 current Application?  
4

5 e) Please provide a schedule that sets out the base year values for the Ontario Demand and each  
6 of the three Charge Determinant and their forecast (to 2027) annual values based on each of  
7 the three forecasting models and Hydro One’s proposed forecast.  
8

9 **Response:**

10 a) Values for 2019 and 2020 are actual. They have been presented alongside the forecast for  
11 reference, as in previous rate applications. Hydro One confirms that the base year for the  
12 forecast is 2020 and that growth rates are applied to weather normalized values as indicated  
13 on page 6 of D-4-1.  
14

15 b) In Table 3 and Appendix G, data up to 2020 are actual and other subsequent figures are  
16 forecast.  
17

18 c) The forecast growth rates presented in the following table are gross of the load impact of  
19 CDM and Embedded Generation when applicable.  
20

Year	Monthly Econometric	Annual Econometric	End-Use	Average	Used
2021	1.14	1.43	0.32	0.96	1.06
2022	-0.06	0.25	0.16	0.12	0.66
2023	0.65	-0.34	-0.11	0.07	0.75
2024		-0.43	-0.02	-0.22	0.40
2025		-0.35	-0.04	-0.19	0.30
2026		-0.19	-0.09	-0.14	0.39
2027		-0.29	-0.08	-0.19	0.54

21  
22 The growth rates used in the proposed forecast are higher compared to the average forecast  
23 growth rate implied by the forecasting model in view of other considerations including  
24 developments in Leamington and surrounding areas and to account for potential additional  
25 load growth due to other factors (e.g., EVs) that could materialize. These adjustments reflect  
26 a high-side risk on the forecast to the benefit of customers.  
27

28 d) Confirmed.

1 e) Please see below the requested forecasts.

2

**Table 1. Load Forecast, Net of the Impact of CDM and Embedded Generation,  
 Based on Monthly Econometric Model**

12-Month Average Peak in MW	2020	2021	2022	2023
<b>Ontario Peak</b>	19219	19356	19240	19288
<b>Charge Determinant Forecast</b>				
Network	19023	19158	19043	19091
Line Connection	18435	18596	18485	18530
Transformation Connection	15682	15819	15724	15763

3

**Table 2. Load Forecast, Net of the Impact of CDM and Embedded Generation,  
 Based on Annual Econometric Model**

12-Month Average Peak in MW	2020	2021	2022	2023	2024	2025	2026	2027
<b>Ontario Peak</b>	19219	19419	19371	19199	19092	18968	18875	18712
<b>Charge Determinant Forecast</b>								
Network	19023	19220	19172	19003	18897	18774	18682	18520
Line Connection	18435	18655	18609	18446	18344	18226	18137	17981
Transformation Connection	15682	15869	15830	15691	15604	15504	15428	15296

4

**Table 3. Load Forecast, Net of the Impact of CDM and Embedded Generation,  
 Based on End-Use Model**

12-Month Average Peak in MW	2020	2021	2022	2023	2024	2025	2026	2027
<b>Ontario Peak</b>	19219	19176	19109	18990	18973	18918	18847	18731
<b>Charge Determinant Forecast</b>								
Network	19023	18980	18914	18795	18779	18725	18654	18539
Line Connection	18435	18424	18360	18246	18231	18178	18110	17999
Transformation Connection	15682	15673	15618	15521	15508	15464	15406	15311

5

**Table 4. Load Forecast, Net of the Impact of CDM and Embedded Generation,  
 Based on Used Growth Rates**

12-Month Average Peak in MW	2020	2021	2022	2023	2024	2025	2026	2027
<b>Ontario Peak</b>	19219	19338	19381	19451	19527	19547	19584	19607
<b>Charge Determinant Forecast</b>								
Network	19023	19140	19183	19252	19327	19347	19384	19406
Line Connection	18435	18563	18622	18689	18761	18780	18816	18837
Transformation Connection	15682	15791	15841	15898	15959	15975	16006	16024

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Witness: ALAGHEBAND Bijan

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 044**

2  
3 **Reference:**

4 Exhibit D-4-1, Page 5-7 and 16-18

5  
6 **Interrogatory:**

7 a) With respect to Table 3 (page 17) please explain how the impacts of Embedded Generation  
8 on the 12 Month Average Peak values for each of Ontario Demand, Network Connection, Line  
9 Connection and Transformation Connection were derived from the system embedded  
10 generation impacts noted on page 6.

11  
12 b) With respect to Table 3 (page 17) please explain how the impacts of CDM on the 12 Month  
13 Average Peak values for each of Network Connection, Line Connection and Transformation  
14 Connection were derived from the CDM impacts set out on page 5.

15  
16 **Response:**

17 a) Embedded Generation for each charge determinant is measured in proportion of the charge  
18 determinant to Ontario peak, with the following exception: For line connection and  
19 transformer connection, the actual load is already measured gross of co-generation so this  
20 portion of embedded generation is excluded from overall embedded generation for these two  
21 charge determinants to avoid double-counting co-generation.

22  
23 b) The impact of CDM for each charge determinant is measured in proportion of the charge  
24 determinant to Ontario peak.



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EB-2021-0110  
Exhibit I  
Tab 24  
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Witness: ALAGHEBAND Bijan

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 045**

2  
3 **Reference:**

4 Exhibit D-5-1, Page 1 and 7

5  
6 **Preamble:**

7 The Application states (page 1): "All forecasts presented in this section are weather-normal, and  
8 the numbers are at the wholesale level unless otherwise specified". The Application states (page  
9 7): "The load forecast also takes into account 2020 actual load".

10  
11 **Interrogatory:**

- 12 a) Please explain what is meant by the "wholesale level".
- 13
- 14 b) Please indicate for which tables in the Exhibit D, Tab 5 (including the Appendices and  
15 associated Excel Spreadsheets) the data presented is not at the "wholesale level" and, in each  
16 case, explain at what point the data is being measured.
- 17
- 18 c) For each customer class please indicate the loss factor the wholesale values reported would  
19 need to be divided by in order to obtain the kWh delivered to the customer.
- 20
- 21 d) Are all of the 2020 kWh and kW values used in Exhibit D, Tab 5 (including the Appendices and  
22 associated Excel Spreadsheets) actual values or weather normalized actual values (as opposed  
23 to a forecast value)? If not, please indicate for which tables and spreadsheets the 2020 values  
24 are not actuals and explain what the basis for the 2020 values in such cases is.
- 25
- 26 e) Are all of the 2020 customer count values used in Exhibit D, Tab 5 (including the Appendices  
27 and associated Excel Spreadsheets) actual values (as opposed to a forecast value)? If not,  
28 please indicate for which tables and spreadsheets the 2020 values are not actuals and explain  
29 what the basis for the 2020 values in such cases is.

30  
31 **Response:**

- 32 a) Wholesale means at purchase level and, as such, includes distribution losses.
- 33
- 34 b) All figures in the Exhibit noted above are at wholesale level except those related to sales  
35 (Tables E.5, E.6, E.8). By definition, sales figures exclude distribution losses.
- 36
- 37 c) The loss factors are presented in the following table.

Witness: ALAGHEBAND Bijan

Loss Factors	
	Total (Sec)
UR	1.057
R1	1.076
R2	1.105
Seasonal	1.104
GSe	1.096
GSd	1.061
UGe	1.067
UGd	1.050
USL	1.092
ST	1.034
Dgen	1.061
STL	1.092
Sen Lgt	1.092
AUR	1.043
AUGe	1.043
AUGd	1.033
AR	1.064
AGSe	1.064
AGSd	1.053

1

2 d) All 2020 kWh and kW figures in Exhibit D-5-1 (including the Appendices and associated Excel  
3 spreadsheets) are actual or weather-normalized actual values, not forecast.

4

5 e) All 2020 customer counts in Exhibit D-5-1 (including the Appendices and associated Excel  
6 spreadsheets) are actual values not forecast.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 046**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 8 and 37

5  
6 **Interrogatory:**

- 7 a) What is the basis for the customer counts referenced on page 8 and set out in Table E.3 (i.e.,  
8 are they year-end values, average of 12 months values, or determined on some other basis)?  
9
- 10 b) For the Street Light, Sentinel and USL classes do the values in Table E.3 represent the number  
11 of customers, number of connections or number of devices?  
12
- 13 c) Please provide the customer count for each class as of June 30, 2021 and July 31, 2021. For  
14 the Seasonal class, please indicate the breakdown between those in the UR, R1 and R2  
15 geographic areas.  
16

17 **Response:**

- 18 a) Customer counts are mid-year values.  
19
- 20 b) The values represent number of contracts.  
21
- 22 c) The requested information is not readily available.

Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
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Witness: ALAGHEBAND Bijan

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 047**

2  
3 **Reference:**

4 Exhibit D-5-1, Page 8

5  
6 **Preamble:**

7 The Application states: "The customer forecast takes into consideration new customers requiring  
8 distribution services, existing customers moving out, provincial housing demand, population and  
9 household forecasts, vacancy rates and specific growth patterns of various customer groups".

10  
11 **Interrogatory:**

- 12 a) Please provide a schedule that sets out the derivation of the forecast customer count for each  
13 Residential class (including Seasonal and Acquired Utilities) for each of the years 2021-2027.  
14 In doing so please provide all equations, inputs used and associated calculations.  
15
- 16 b) If not dealt with in the previous question, please explain how Seasonal customer are dealt  
17 with for purposes of the customer count forecast (e.g., was the Seasonal count forecast for  
18 each year through to 2027 and then assigned to the other Residential classes or was the  
19 Seasonal customer forecast for 2022 assigned to the other Residential classes and then  
20 forecasts for those classes developed for 2023 and afterwards using adjusted 2022 values?).  
21
- 22 c) Please provide a schedule that sets out the derivation of the forecast customer count for each  
23 General Service class (including each Acquired GS class) for each of the years 2021-2027. In  
24 doing so please provide all equations, inputs used and associated calculations.  
25
- 26 d) Please provide a schedule that sets out the derivation of the forecast customer count for the  
27 ST customers for each of the years 2021-2027. In doing so, please explain how the forecast  
28 methodology accounts for the fact the customer numbers for Norfolk, Haldimand and  
29 Woodstock are integrated into Hydro One Distribution for 2023 onwards.  
30
- 31 e) Please provide a schedule that sets out the derivation of the forecast customer count for the  
32 Street Light, Sentinel Light and USL classes for each of the years 2021-2027.

1 f) Have the forecast customer counts for the ST class and the General Service (demand) classes  
2 been adjusted to account for GS customers that will now qualify as ST customer based on  
3 Hydro One Distribution's proposal to change the ST class eligibility requirements (per L/1/2,  
4 page 3)?

5 i. If yes, specifically what adjustments were made?  
6

7 g) Please provide a working excel version of Table E.3.  
8

9 **Response:**

10 a) Please see Excel Attachment I-24-D-VECC-047-01 to this response.  
11

12 b) As shown in the response to part a), the Seasonal customer count was forecast for each year  
13 through 2023 to 2027 and then assigned to the other Residential classes.  
14

15 c) Please see response to part a)  
16

17 d) Please see answer to part a)  
18

19 e) Please see response to part a)  
20

21 f) Yes, in 2023, 6 UGD and 21 GSD customers move to ST.  
22

23 g) Please see Excel Attachment I-24-D-VECC-047-02 to this response.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 048**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 5, 7, and 18

5  
6 **Interrogatory:**

- 7 a) With respect to Table 3, does the customer count for 2021 and 2022 treat the Acquired  
8 Utilities as ST customers but, for the years 2023 onwards, include each retail customer of the  
9 Acquired Utilities as a separate customer? If not, how are the Acquired Utilities treated for  
10 purposes the customer counts in Table 3?  
11
- 12 b) With respect to Table 3, does the GWh Delivered Forecast for 2021 and 2022 include the  
13 Acquired Utilities as ST customers but for 2023 onwards assume their retail customers are  
14 retail customers of Hydro One Distribution? If not, how are the Acquired Utilities treated for  
15 purposes the GWH Delivered Forecast in Table 3?  
16
- 17 c) In Table 3, does the integration of the load for the Acquired Utilities into Hydro One  
18 Distribution in 2023 impact the value for the Delivered GWh for that year? If yes, please  
19 explain why and indicate what the GWh impact is.  
20
- 21 d) With respect to Table 4, is the CDM attributable to the Acquired Utilities reported as LDC CDM  
22 for 2019-2022 and then as Retail Customer CDM for 2023 onwards? If not, how is it reported?  
23
- 24 e) In Table 4, does the change in the reporting of the CDM attributable to Acquired Utilities  
25 change the total CDM for 2023? If yes, please explain why and what the GWH impact is.  
26
- 27 f) In Table 4, is the increase is LDC CDM in 2023 over 2022 (70 GWh) net of any the reduction  
28 that would occur due to the integration of the Acquired Utilities into Hydro One Distribution?  
29 If so, what was the reduction associated with the integration?  
30

31 **Response:**

- 32 a) Yes, with the exception that Woodstock has never been embedded in Hydro One Distribution  
33 and, as such, has not been an ST customer.  
34
- 35 b) Yes, with the exception that Woodstock has never been embedded in Hydro One Distribution  
36 and, as such, has not been an ST customer. Moreover, only a portion of load for Haldimand  
37 and Norfolk has been embedded.

Witness: ALAGHEBAND Bijan



- 1 c) Yes, the GWh impact is reflected in the sum of GWh in that table for the year 2023, because  
2 the Acquired LDC load in that year is Hydro One customer load. In that year Acquired Utility  
3 load is 1,140 GWh.  
4
- 5 d) Yes. However, Woodstock has never been a Hydro One embedded customer, and only a  
6 portion of Norfolk and Haldimand load has been embedded in Hydro One.  
7
- 8 e) Yes, because Woodstock has never been an ST customer and only a portion of Haldimand and  
9 Norfolk were embedded in Hydro One. Thus, total CDM would have been reduced by 149  
10 GWh.  
11
- 12 f) Yes, and the amount was 33.9 GWh.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 049**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 11, 18, and 20-21 (Appendix A)

5  
6 **Preamble:**

7 The Application (page 11) states: "Both monthly and annual econometric models are used to  
8 forecast Hydro One Distribution's total distribution system load."

9  
10 **Interrogatory:**

- 11 a) With respect to the Monthly Econometric Model, what historical years were used to estimate  
12 the regression model?  
13
- 14 b) At page 20, the Application states that the dependent variable is the logarithm of retail load.  
15 Have the historic retail load values used to estimate the regression equation been weather-  
16 normalized? If not, how are weather impacts accounted for?  
17
- 18 c) At page 20, the Application states that the dependent variable is the logarithm of retail load.  
19 However, page 11 states that the monthly econometric model was used to forecast total  
20 distribution system load. Please confirm that Hydro One's reference to total distribution load  
21 forecast excludes the ST customers but includes all of the other customer classes. If not  
22 confirmed, what customer classes are included in the load used as the dependent variable for  
23 the Monthly Econometric Model?  
24
- 25 d) For the historical period used for the Monthly Econometric Model have the same LDCs and  
26 Direct customers been treated as ST customers and their load excluded throughout.  
27
- 28 e) Please explain how the Monthly Econometric Model accounted for the fact that Norfolk,  
29 Haldimand and Woodstock are ST customers for 2021 and 2022 by then into Hydro One  
30 Distribution for 2023 onwards. If the load forecast for the retail customers in these utilities  
31 was for 2023 onwards was done separately, please explain the basis for the forecast.  
32
- 33 f) Does the forecast result for the Monthly Econometric Model reflect the same definition of  
34 Retail as used in Table 5 (D/5/1, page 18)?

1

2 **Response:**

3 a) From 1979 to 2020.

4

5 b) Yes.

6

7 c) The dependent variable is the logarithm of retail load.

8

9 d) A subset of retail General Service customers that were moved to ST were added back to retail  
10 load to have a consistent series.

11

12 e) For Norfolk, Haldimand, and Woodstock separate forecasts were developed using  
13 econometric analysis.

14

15 f) As noted in response to part d), the load of some General Service customers that had moved  
16 to ST were added back to the retail load to have a consistent series for modelling purposes.  
17 In Table 5 noted above, actual retail load (excluding such ST customers) is presented.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 050**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 11 and 22-27 (Appendix B)

5  
6 **Preamble:**

7 The Application (page 11) states: "Both monthly and annual econometric models are used to  
8 forecast Hydro One Distribution's total distribution system load."

9  
10 Appendix B states: "In this Appendix, regression results for annual econometric models are  
11 presented. As explained in the main text, in each case, two sets of results are provided; one base  
12 on Toronto weather data and the other on average weather data for 5 weather stations across  
13 Ontario (Thunder Bay, Windsor, Toronto, Ottawa, and North Bay). The results are discussed in  
14 Section 2.2."

15  
16 **Interrogatory:**

- 17 a) With respect to the Annual Econometric Model, what historical years were used to estimate  
18 the regression model?  
19
- 20 b) Please confirm that the reference in Appendix B should be to section 3.2 (D/5/1) and not  
21 section 2.2.  
22
- 23 c) Does the retail load used as the dependent variable in the Annual Econometric Model include  
24 the same customer classes as that used in the Monthly Econometric Model? If not, what are  
25 the differences?  
26
- 27 d) It is noted that the Annual Econometric Model does not include cooling degree days as a  
28 dependent variable. Please explain why.  
29
- 30 e) For the historical period used for the Annual Econometric Model have the same LDCs and  
31 Direct customers been treated as ST customers and their load excluded throughout?  
32
- 33 f) Please explain how the Annual Econometric Model accounted for the fact that Norfolk,  
34 Haldimand and Woodstock are ST customers for 2021 and 2022 by then into Hydro One  
35 Distribution for 2023 onwards. If the load forecast for the retail customers in these utilities  
36 was for 2023 onwards was done separately, please explain the basis for the forecast.  
37

Witness: ALAGHEBAND Bijan

1 g) Do the forecast results for the Annual Econometric Model reflect the same definition of Retail  
2 as used in Table 5 (D/5/1, page 18)? If not, what is the difference?  
3

4 **Response:**

5 a) For retail load it is 1970 to 2020.  
6

7 b) Confirmed.  
8

9 c) They are the same, except that actual load is used in the annual model and weather corrected  
10 actual in the monthly model.  
11

12 d) Cooling degree days was not included in the model because it did not have a statistically  
13 significant coefficient. Nonetheless, a higher heating degree day normally coincides with a  
14 lower cooling degree day so that the former reflects the net impact of heat and cooling degree  
15 days on the load.  
16

17 e) As in the monthly econometric model, retail load includes a subset of General Service  
18 customers that were moved to ST, whose load was added back to retail load to have a  
19 consistent series.  
20

21 f) Please see response to D -VECC -49, part e).  
22

23 g) Please see response to D -VECC -49, part f).

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 051**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 11 and 28-30

5  
6 **Preamble:**

7 The Application (page 18) state: "End-use models are used to analyze the distribution system load  
8 by customer rate class".

9  
10 **Interrogatory:**

- 11 a) What is the base year used in the End-Use Model and is it the same for all sectors?  
12  
13 b) Do the combined Residential, Commercial, Industrial and Agricultural sectors (per the End-  
14 Use Model) represent the same customer classes as the Retail Load used as the dependent  
15 variable in the Monthly Econometric Model? If not, please explain the difference.  
16  
17 c) Please explain how the End-Use Model accounted for the fact that Norfolk, Haldimand and  
18 Woodstock are ST customers for 2021 and 2022 by then into Hydro One Distribution for 2023  
19 onwards. If the load forecast for the retail customers in these utilities was for 2023 onwards  
20 was done separately, please explain the basis for the forecast.  
21  
22 d) Do the forecast results for the End-Use Model reflect the same definition of Retail as used in  
23 Table 5 (D/5/1, page 18)? It not, what is the difference?  
24  
25 e) Please provide a schedule that, of each of the three models (Monthly Econometric, Annual  
26 Econometric and End-Use, sets out the actual 2020 weather normalized energy (before  
27 deducting CDM) and reconcile the differences with the 2020 value set out in Table 5 (page 18)  
28 for Retail Customers.  
29

30 **Response:**

- 31 a) 2020.  
32  
33 b) In the End-Use model, all ST non-LDC customers are included in Hydro One load.  
34  
35 c) The End-Use model considers Hydro One retail load excluding Acquired LDCs. For details on  
36 the separate forecasts for acquired utilities, please see response to D-VECC-49, part e).  
37

Witness: ALAGHEBAND Bijan

- 1 d) No, and the difference is that End-Use retail load includes ST non-LDC load.  
2  
3 e) The 2020 weather normalized energy (before deducting CDM) for monthly and annual  
4 econometric models is 23,504 GWh, of which 2,181 GWh accounts for general service  
5 customer that had moved to ST. To have consistent series, the latter amount was added to  
6 retail load. Deducting back 2,181 GWh from 23,504 GWh, we obtain the 21,323 GWh shown  
7 in Table 5 noted above.

8

9	2020 Gross Value	23,504
10	Deduct GS moved to ST	-2,181
11	Gross Retail Load	21,323

12

13 The 2020 End-Use model starts with 2020 actual and forecast includes incremental CDM  
14 relative to the 2020 base year value. The 2020 weather normalized energy for the End-Use  
15 model including ST non-LDC (i.e., ST Direct) is 24,444. Deducting from the latter figure ST non-  
16 LDC load of 5,295 GWh, we obtain 19,149 GWh. Finally, adding the 2020 CDM effect of 2,174  
17 to the latter figure we obtain 21,323 GWh, which is the retail gross load as shown in Table 5  
18 noted above.

19

20	2020 Net Value	24,444
21	Deduct ST non-LDC	-5,295
22	Add CDM	<u>2,174</u>
23	Gross Retail Load	21,323

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 052**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 16-18

5  
6 **Interrogatory:**

- 7 a) Please provide a schedule that sets out;
- 8 i. The actual weather normalized Retail Load for 2016 (before deducting impact of CDM)
  - 9 ii. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on
  - 10 the Monthly Econometric Model (before deducting CDM).
  - 11 iii. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on
  - 12 the Annual Econometric Model (before deducting CDM).
  - 13 iv. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on
  - 14 the End Use Model (before deducting CDM).
  - 15 v. The actual Retail load for 2020 and the forecast Retail load for 2021-27 per the Application
  - 16 (before deducting impact of CDM).
- 17
- 18 b) With respect to the response to part (a), was the same forecast used for the 2023-2027 retail
- 19 load associated with the Acquired Utilities for all three models. If not please provide the 2023-
- 20 2027 forecast for the retail load associated with the Acquired Utilities included in each
- 21 Model's results and in the 2023-2027 forecast Retail load per the Application (Table 5).
- 22
- 23 c) Please provide the detail calculations setting out how the proposed Retail load forecast
- 24 (before deducting CDM) for each of the years 2021 to 2027 was determined using the results
- 25 of these three models.
- 26
- 27 d) Have the forecast customer volumes for the ST class and the General Service (demand) classes
- 28 been adjusted to account for GS customers that will now qualify as ST customer based on
- 29 Hydro One Distribution's proposal to change the ST class eligibility requirements (per L/1/2,
- 30 page 3)?
- 31 a) If yes, specifically what adjustments were made?



1 **Response:**

2 a)

3 i. It is 21,896 GWh.

4  
5 ii. The requested information is provided in the following table. The 2020 value was  
6 available as shown in the following table. The model predicted value for 2020 is not  
7 available due to State-Space nature of the forecasting model.  
8

Year	Monthly Econometric	Annual Econometric	End-Use	Forecast Used in the Application
2020	21,323	21,323	21,323	21,323
2021	21,014	20,742	21,288	21,519
2022	21,250	20,489	21,242	21,730
2023*	22,829	21,643	22,650	23,123
2024*		21,749	22,744	23,240
2025*		21,917	22,619	23,327
2026*		22,129	22,698	23,396
2027*		22,372	22,799	23,644

\* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

9  
10 iii. The predicted 2020 is 21,557 GWh, and actual 21,323; these values exclude retail load  
11 moved to ST as explained in response to part e) and are weather normalized. For forecast,  
12 after deducting retail load moved to ST, please see response to part ii)

13  
14 iv. The model predicted value for 2020 is not available due to the nature of the End-Use  
15 forecasting model. Please see response to part ii) for the 2020 actual and forecast values  
16 for 2021-2027.

17  
18 v. Please see response to part a) ii).

19  
20 b) Yes.

21  
22 c) The forecasts from the three models cited above were examined and, to mitigate uncertainty  
23 involved in the future state of the economy in a “rapidly evolving situation” and speed of EV  
24 and electrification and other developments, a forecast higher than each of these 3 forecasts  
25 was arrived at for this Application to the benefit of customers, as shown in response to part  
26 ii). This can also be observed in the growth rates of forecasts discussed in part ii), as presented  
27 below.

Year	Monthly Econometric	Annual Econometric	End-Use	Average	Forecast Used in the Application
2021	-1.4	-2.7	-0.2	-1.4	0.9
2022	1.1	-1.2	-0.2	-0.1	1.0
2023*	7.4	5.6	6.6	6.6	6.4
2024*		0.5	0.4	0.5	0.5
2025*		0.8	-0.6	0.1	0.4
2026*		1.0	0.4	0.7	0.3
2027*		1.1	0.4	0.8	1.1

\* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

1  
 2  
 3

d) Yes, the adjustments are presented in the following table.

Adjustment	2023	2024	2025	2026	2027
Moved from GSd to ST	58.2	57.7	57.3	56.9	56.5
Moved from UGd to ST	13.6	13.6	13.5	13.5	13.4

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Witness: ALAGHEBAND Bijan

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 053**

2

3 **Reference:**

4 Exhibit D-5-1, Pages 13, 18 and 38

5

6 **Interrogatory:**

7 a) Please explain how the forecast of 2021-2027 forecast for total Retail load (per page 18) is  
8 disaggregated into the individual rate classes (per Table E.5) and provide schedules with the  
9 supporting calculations.

10

11 **Response:**

12 a) First, the forecast of total retail load is disaggregated into different rate classes based on  
13 historical patterns. Next, the impact of customer reclassification is considered. Please see  
14 Excel Attachment I-24-D-VECC-053-01 to this response for further details.

Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
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Page 2 of 2

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Witness: ALAGHEBAND Bijan

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 054**

2

3 **Reference:**

4 Exhibit D-5-1, Page 17

5

6 **Preamble:**

7 The Application states: "The peak forecast for each rate class is derived from corresponding sales  
8 forecast using load factor."

9

10 **Interrogatory:**

11 a) Please explain how the "load factor" used for each rate class was determined.

12

13 **Response:**

14 a) The growth rate of sales forecast was applied to the corresponding peak value in 2020. The  
15 ratio of peak to sales is presented in the following table.

16

	2020	2021	2022	2023	2024	2025	2026	2027
DGEN	6,948	6,948	6,948	6,948	6,948	6,948	6,948	6,948
GSd	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205
UGd (1)	2,626	2,620	2,614	2,608	2,602	2,596	2,590	2,584
ST *	2,040	2,040	2,040	2,044	2,044	2,044	2,044	2,044
Acquired GSd	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794
Acquired UGd	2,819	2,819	2,819	2,819	2,819	2,819	2,819	2,819

(1) UGD peak is expected to grow slower than sales.

\* Includes the impact of integrating Acquired Utilities for the years 2023 to 2027 only. The integration also  
leads to a small change in the peak to sales ratio.

17

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1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 055**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 6 and 13-14

5  
6 **Preamble:**

7 The Application (page 13) states: "ST customers include embedded distribution utilities, or large  
8 industrial and commercial customers. Both econometric and customer analysis based on survey  
9 results from the customers, when available, are used in the forecast. This is supplemented by the  
10 economic data provided in the economic forecast."

11  
12 The Application also states (page 14): "The econometric approach was used to forecast the load  
13 for embedded utilities and industrial analysis was used to forecast the load for the embedded  
14 industrial customers. In both cases, results from the customer survey were taken into account in  
15 developing the forecast."

16  
17 **Interrogatory:**

18 a) Please outline the econometric analysis used to forecast the embedded distribution utility  
19 load. As part of the response please indicate how the analysis addressed the fact that the  
20 Acquired Utilities are only ST customers for 2021 and 2022.

21  
22 b) Please provide a schedule that sets out:

- 23 i. The actual (weather corrected) embedded distribution utility load for 2020 and the  
24 forecast values for 2021-2027 per the Application (before deducting CDM).  
25 ii. The predicted embedded distribution utility load (before deducting CDM) for 2020-2027  
26 based on the econometric analysis.  
27 iii. How the customer survey results were taken into account in developing the forecast.

28  
29 **Response:**

30 a) Please see Exhibit D-5-1, Appendix B for the model used to forecast Embedded Utilities load.  
31 The embedded portion of Acquired Utilities during the historical period is included in the  
32 actual and so is the forecast implied by that model. For the years 2023 to 2027, forecast of  
33 Acquired Utilities, which are arrived at separately, are deducted from the Embedded utility  
34 load forecast. It should be noted that Woodstock had never been a Hydro One Embedded  
35 Utility, and only a portion of Norfolk and Haldimand load was embedded.



1 b)

2 i. The requested information is presented in the following table.

3

Year	GWh
2020	11,802
2021	11,922
2022	12,045
2023 *	11,839
2024 *	11,946
2025*	12,031
2026*	12,088
2027*	12,135

4

5 ii. Please see response to Part b) i).

6

7 iii. Customer survey had limited responses and was supportive of the econometric results.  
8 For example, the results were used to see if the customer expects a new plant  
9 development or closure.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 056**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 6 and 13-14

5  
6 **Preamble:**

7 The Application (page 13) states: "ST customers include embedded distribution utilities, or large  
8 industrial and commercial customers. Both econometric and customer analysis based on survey  
9 results from the customers, when available, are used in the forecast. This is supplemented by the  
10 economic data provided in the economic forecast."

11  
12 The Application also states (page 14): "The econometric approach was used to forecast the load  
13 for embedded utilities and industrial analysis was used to forecast the load for the embedded  
14 industrial customers. In both cases, results from the customer survey were taken into account in  
15 developing the forecast."

16  
17 **Interrogatory:**

- 18 a) Please outline the industrial analysis used to forecast the Direct (i.e., large industrial and  
19 commercial) load.  
20  
21 b) Please provide a schedule that sets out:  
22 i. The actual (weather corrected) Direct customer load for 2020 and the forecast for 2021-  
23 2027 per the Application (before deducting CDM).  
24 ii. The predicted Direct customer load (before deducting CDM) for 2020-2027 based on the  
25 industrial analysis.  
26 iii. How the customer survey results were taken into account in developing the forecast.  
27

28 **Response:**

- 29 a) The industrial analysis was based on several considerations including knowledge through  
30 tracking industrial news by sector, information provided by planners/customers, historical  
31 trend taking into account the impact of the pandemic on different industries.  
32  
33 b)  
34 i. The requested information is presented in the following Table.

Year	GWh
2020	5,004
2021	5,025
2022	5,053
2023 *	5,234
2024 *	5,220
2025*	5,205
2026*	5,204
2027*	5,314

1  
2  
3  
4  
5  
6

- ii. There was not a separate forecast based on industrial analysis alone.
- iii. As noted in response to Part a), various factors were involved in preparing the forecast for Direct load, including a limited number of survey results. For example, the results were used to see if the customer expects a new plant development or closure.

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 057**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 7 and 18

5  
6 **Interrogatory:**

- 7 a) Please explain how CDM is defined for purposes of Tables 4 and 5 (e.g., does it just include  
8 the impact or OPA/IESO and distributor-funded efficiency programs?).  
9
- 10 b) Tables 4 and 5 only show the impact of CDM on Retail and ST Customers for 2019 and after.  
11 Please provide a schedule as to the annual impact of CDM on each of Retail Load and ST Load  
12 (broken down between Direct and LDC) for each historical years used to estimate the Monthly  
13 Econometric Model and/or the Annual Econometric Model. If CDM includes more than just  
14 the impact of energy efficiency programs, please provide a further breakdown by CDM  
15 component.  
16
- 17 c) Please provide the source documents (or their web-links) from which the historic values  
18 provided in part (b) were derived and any supporting calculations regarding their derivation.  
19
- 20 d) Are the historical CDM values used by Hydro One consistent with those published by the IESO  
21 in its most recent Annual Planning Outlook (APO) and previous publications?  
22 i. If not, why not?  
23 ii. If yes, please provide schedule that sets out the actual CDM savings reported by the IESO  
24 in its most recent APO and previous publications for the historic period used by Hydro  
25 One in its econometric models and demonstrate how the values used by Hydro One are  
26 consistent.  
27

28 **Response:**

- 29 a) The CDM impact on Hydro One distribution load can be grouped in the following categories,  
30 which are also used by the IESO:
- 31 • Non-target CDM programs (2005-2010) initiated by both Hydro One and the OPA
  - 32 • Target CDM programs (2011-2014 and 2015-2020) initiated by the IESO (former OPA)
  - 33 • CDM programs funded by other organizations, such as federal, provincial, and/or  
34 municipal governments, natural gas companies, and other non-government  
35 organizations
  - 36 • CDM impacts from code and standards

1 b) The requested information is presented in GWh in the following table. Hydro One does not  
 2 have EE and C&S savings broken down by the categories requested in this interrogatory.  
 3 Please refer to the response to part c). Hydro One does not have the breakdown for 2006-  
 4 2021.  
 5

Year	Retail	Direct	LDC
2006	195	20	112
2007	430	45	245
2008	491	51	280
2009	606	63	346
2010	670	70	382
2011	845	88	482
2012	985	108	582
2013	1092	128	629
2014	1414	159	795
2015	1619	169	856
2016	1810	195	929
2017	1982	209	957
2018	2164	236	1172
2019	2154	247	1043

6  
 7 c) The CDM savings for HONI distribution is based on the total energy savings for Ontario. The  
 8 following table lists the data sources for the 2006-2027 savings.  
 9

	EE+ C&S	Data Source
2006	OPO 2018 Slide 19	D-VECC-057 Attachment 1
2007		
2008		
2009		
2010		
2011		
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019	Information from the IESO in Feb 2021	G-VECC-092 Attachment 1
2020		
2021		
2022	APO Current fraemwork (Figure 20) + Near term framework (Figure 21)+ Long term framework senair o 2 (Figure 22)	APO 2020 Figure 23  <a href="https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook">https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook</a>
2023		
2024		
2025		
2026		
2027		

1 d)

2 i. They are not exactly the same, however the difference is insignificant. The table below  
3 compares the CDM savings for 2015-2019 used in the load forecasting and APO 2020.  
4

TWh	2015	2016	2017	2018	2019
CDM Used in the LF	13.93	15.55	17.27	19.31	19.41
APO2020	13.97	15.03	17.24	19.34	19.48

5

6 The reasons that Hydro One did not use APO 2020 for 2015-2020 are:

- 7
- 8 • APO 2020 only provides historical savings for 2015-2019, but not 2006-2014. To  
9 construct a consistent set of saving values for 2006-2018, we used the OPO 2018  
10 information which is consistent with the data used in the application of EB-2017-  
11 0049.
  - 12 • We used the savings for 2019-2021 from the IESO in Feb 2021 since APO 2020 does  
13 not provide savings for 2020-2021.

13

14 ii. Not applicable.

Filed: 2021-11-29  
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Witness: ALAGHEBAND Bijan

1 **D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 058**

2  
3 **Reference:**

4 Exhibit D-5-1, Pages 7 and 18

5  
6 **Preamble:**

7 The Application states (page 7): "The CDM figures for all years are consistent with IESO Annual  
8 Planning Outlook (APO), including the load impact of LDC energy efficiency programs for the years  
9 2019-2020. The methodology for incorporating CDM into the load forecast is described in Section  
10 3 of this Exhibit".

11  
12 **Interrogatory:**

- 13 a) Please provide the CDM figures per the IESO's APO (along with a copy or link to the actual  
14 document) and demonstrate that the CDM values used by Hydro One for Retail customers,  
15 Direct Customers and Embedded LDCs for the period 2019-2027 were derived from and/or  
16 are consistent with the IESO's values.
- 17
- 18 b) Are the Hydro One's incremental CDM savings in 2019 and 2020 consistent with the targets  
19 set out by the IESO in its Interim Framework for the period April 1, 2019 to December 31,  
20 2020?
- 21 i. If not, why not?
- 22 ii. If yes, please provide a schedule that reconciles the incremental CDM savings Hydro  
23 One has assumed for 2019 and 2020 with the Interim Framework's targets.
- 24
- 25 c) Are the Hydro One's incremental CDM savings in 2021-2024 consistent with the targets set  
26 out by the IESO in its 2021-2024 Conservation and Demand Management Framework Program  
27 Plan?
- 28 i. If not, why not?
- 29 ii. If yes, please provide a schedule that reconciles the incremental CDM savings Hydro  
30 One has assumed for 2021-2024 Conservation and with the targets in the IESO's 2021-  
31 2024 CDM Framework.



1 **Response:**

2 a) See response to VECC-057.

3

4 b)

5 i. No. The 2019-2020 interim framework set out savings targets for the programs delivered  
6 by the IESO, however the CDM categories Hydro One used also include all EE programs  
7 and codes and standards (C&S).

8 ii. Not applicable.

9

10 c)

11 i. No. The 2021-2024 interim framework set out savings targets for the programs delivered  
12 by the IESO, however the CDM categories Hydro One used also include all EE programs  
13 and C&S.

14 ii. Not applicable.

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 059**

2  
3 **Reference:**

4 Exhibit D-1-1, Page 13

5 Exhibit E-2-1, Page 8

6  
7 **Preamble:**

8 Hydro One suggests that reduction in OM&A following the completion of the PCB program is  
9 unwarranted. The Utility further states that upon completion of the PCB Program it *"plans to*  
10 *resume preventive maintenance on transmission stations and lines assets that were deferred in*  
11 *2019-2022."* The Utility also suggests that the resources currently used on the PCB program will  
12 be redirected to correct 'defects' which have grown by *"an average of approximately 11,500*  
13 *defects per year."*

14  
15 **Interrogatory:**

- 16 a) At E-2-1, page 3 Hydro One states that it needs to increase OM&A spending starting in 2023  
17 to *"address deferred stations maintenance that allowed Hydro One to continue funding PCB*  
18 *remediation work as planned in 2019-2022."* If Hydro One is already increasing spending in  
19 2023 for station remediation than how can it also be true that it would be "unwarranted" to  
20 reduce OM&A spending upon completion of the PCB program?  
21  
22 b) Is the PCB program currently being executed by Hydro One staff or third-party contractors or  
23 a combination of the two? Please provide details.  
24  
25 c) Provide number of defects identified and addressed in each of the years 2017-2021.

26  
27 **Response:**

- 28 a) Please see Interrogatory E-Staff-210. The Proposed Treatment of the PCB funding will allow  
29 Hydro One to complete the previously deferred maintenance work during the 2023-2027  
30 period. Some of this deferred maintenance will be funded in 2026-2027 by the funding from  
31 the PCB remediation program once it is completed at year-end 2025.  
32  
33 b) The PCB program is executed by Hydro One staff.

1 c) The table below the outlines the identified, addressed and unaddressed defects. Entering  
2 2017, there was a backlog of defects identified. Accounting for the defects completed over  
3 2017 to 2021 Q3, which addressed a portion of the backlog, Hydro One has still averaged  
4 11,500 unaddressed defects per year.

5

	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021 Q3</b>
# of Lines Defects Identified	14,120	1,787	11,084	28,684	26,995
# of Lines Defects Addressed	29,528	32,393	28,431	34,838	18,288
# of Unaddressed Lines Defects	9,733	955	9,108	26,411	N/A
# of Stations Defects Identified	2864	2443	2701	2958	1622
# of Stations Defects Addressed	2917	2762	2475	2680	1865
# of Unaddressed Stations Defects	288	339	516	905	N/A

6

7 Average # of Unaddressed Lines Defects: 11,552.

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 060**

2  
3 **Reference:**

4 Exhibit E

5 Exhibit A-3-1, Attachment 1, Page 28

6 Exhibit E-2-2, Page 22

7  
8 **Interrogatory:**

9 *"The air-blast circuit breakers are approximately ten times more costly to maintain and four times*  
10 *less reliable than the SF6 circuit breakers."*

11  
12 **Table 13 - Breaker Refurbishment OM&A (\$M)**

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Breaker Refurbishment	3.9	2.2	0.4	1.9	2.0	2.1

13  
14 a) Please explain how the capital plan to replace SF6 breakers impacts the future OM&A costs  
15 for this asset.

16  
17 b) For each year shown in Table 13 please show the number of circuit breakers  
18 refurbished/maintained.

19  
20 **Response:**

21 a) Although newer SF6 breakers have proportionately lower maintenance costs compared to  
22 older breakers, they comprise only a small proportion (9%) of total corrective maintenance  
23 spending. Further, the year-over-year replacement rate for breakers is approximately 3%,  
24 which has a negligible impact on the total OM&A costs associated with the entire fleet of  
25 breakers. Since the last rate filing, the quantity of poor-condition breakers has increased by  
26 2%, and the average age of the fleet has increased by 10%. This produces an offsetting  
27 increase in OM&A expenditures, as older and poor-condition breakers require greater levels  
28 of maintenance and refurbishments. Preventive maintenance and testing are conducted  
29 regardless of age to ensure the proper mechanical operation and electrical integrity of Hydro  
30 One's breaker fleet. Thus, the level of preventive OM&A cost is the same regardless of capital  
31 replacement.

1 b)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Breaker Refurbishment	29	16	8	8	8	8

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 061**

2

3 **Reference:**

4 Exhibit E-1-1, Page 13

5 Exhibit E-2-1, Page 8

6 Exhibit E-5-1

7

8 **Interrogatory:**

9 a) Please provide a list of all major activities (with annual costs above the materiality threshold)  
10 previously outsourced (e.g., Inergi, Capgemini) that will be insourced beginning 2022 or are  
11 planned to be insourced during the new rate plan.

12

13 b) Please provide the same for all major activities previously insourced that are expected to be  
14 outsourced beginning 2021 and during the rate plan.

15

16 c) For each transition (in-to-out and out-to-in) please provide the expected date of that  
17 transition and the actual or forecast one-time costs of the transition.

18

19 d) For each transition, please provide the expected/forecast net savings (or cost) of the change  
20 in program delivery structure and the actual savings (cost) realized.

21

22 e) Please identify any major activity that was transitioned out of then back into the Utility within  
23 the last 7 years.

24

25 **Response:**

26 a) All planned insourcing of activities previously outsourced are described in Exhibit E-05-01,  
27 Section 5.

28

29 b) At this time, there are no other major activities previously insourced that are expected to be  
30 outsourced beginning 2021 and during the rate plan.

31

32 c) Effective dates of all planned insourcing of activities previously outsourced are included in  
33 Exhibit E-05-01, Section 5.

34

35 d) Please refer to interrogatory E-CCC-034, Table 1, which includes Hydro One's costs for  
36 insourcing services, which are more than offset by the reduction in outsourcing fees.

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- 1 e) There were no major activities that were transitioned out of, and then back into Hydro One
- 2 within the last seven years.

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 062**

2

3 **Reference:**

4 Exhibit E-2-1, Page 3

5

6 **Interrogatory:**

7 Starting in 2023 Hydro One needs to increase its OM&A spending in some respects, mainly to: (i)  
8 5 address deferred stations maintenance that allowed Hydro One to continue funding PCB  
9 remediation work as planned in 2019-2022; (ii) address security needs related to evolving security  
10 threats and NERC CIP standard; and (iii) fund planned corrective maintenance work on overhead  
11 lines.

12

13 a) Hydro One proposes to almost double its capital spending on Overhead Lines Refurbishment  
14 Projects (Appendix 2-AA). Will this capital spending result in lowering of maintenance of these  
15 types of assets in 2023 and future years? If not please explain why not.

16

17 **Response:**

18 a) As explained in TSP Section 2.8.6. Hydro One's proposed lines renewal capital investments  
19 have been paced to annually replace a small portion of the overall fleet. As a result, any  
20 maintenance savings resulting from those capital investments are small in relation to the  
21 funding required to maintain the large pool of aging assets that remain in the fleet.  
22 Considering that lines capital investments are forecast to refurbish 1.1% of the fleet each year,  
23 the corresponding OM&A savings due to the difference in maintenance work is \$0.1M.



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Witness: JABLONSKY Donna

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 063**

2  
3 **Reference:**

4 Exhibit E-2-2, Pages 3 and 40

5  
6 **Interrogatory:**

7 a) What is the incremental cost of the Joint Security Centre? Please explain what year the full  
8 annual incremental cost is expected to occur. Please divide these costs into labour and other  
9 OM&A costs.

10  
11 b) Are these costs captured in the Telecommunications (including cybersecurity line of Appendix  
12 2-JC)?

13  
14 **Response:**

15 a) The incremental cost for the Joint Security Operations Centre in 2022 and 2023 is \$2.38M and  
16 \$3.58M, respectively. The incremental OM&A costs are related to labour because Hydro One  
17 already owns the cyber and physical monitoring systems and therefore any associated  
18 ongoing software licensing, maintenance and support costs would not be incremental.

19  
20 b) Yes, these costs are captured in the Protection, Control, Monitoring, Metering and  
21 Telecommunications (including cybersecurity) line in Appendix 2-JC.

Filed: 2021-11-29  
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Witness: MARCOTTE Kevin

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 064**

2

3 **Reference:**

4 Exhibit E-2-2

5

6 **Interrogatory:**

7 a) In 2018 Hydro One spent \$229.4M on Sustainment maintenance activities. Between 2019  
8 and 2021 (forecast) the spending was reduced to an average of \$205.5 per year. In the test  
9 year (2023) the proposal is to increase spending to \$219.6. What are the reasons that Hydro  
10 One underspent on this activity over the past four years as compared to what was spent in  
11 2018 and what is now being sought to be recovered in rates in 2023?

12

13 **Response:**

14 a) The historical spending on Sustainment OM&A and the associated reasons are provided in  
15 Exhibit E-02-02 below Table 1. Please also see Interrogatory E-Staff-210.

Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
Schedule E-VECC-064  
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Witness: JABLONSKY Donna

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 065**

2

3 **Reference:**

4 Exhibit E-2-3, Page 7

5 Exhibit E-3-s, Page 8

6

7 **Interrogatory:**

8

**TX - Table 3 - RD&D Program OM&A  
 (\$Million)**

9

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
RD&D Program	2.2	1.8	2.3	3.4	3.9	3.3

10

**Table 6 - Summary of RD&D OM&A  
 (\$M)**

11

12

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Research Development & Demonstration	3.2	2.6	2.3	5.0	5.0	5.9

13

14 a) Total R&D is proposed to increase by over 60% as compared to 2018 (i.e., \$5.4M to \$9.2M).  
 15 What research programs would Hydro One eliminate should the Board decided that rates  
 16 should fund only the average of the prior 3 actual years (i.e., 2018-2020).

17

18 b) What was the total subscription costs for involvement in the EPRI and CEATI in each of 2018  
 19 through 2021?

20

21 c) Is the R&D budget specific to DX and TX activities or is the amount simply allocated? If the  
 22 latter please explain how this is done.

23

24 d) What portion of the proposed R&D (combined) is for subscription costs?

25

26 **Response:**

27 a) Should the Board disallow certain expenditures, Hydro One would re-evaluate OM&A  
 28 proposals within the context of its investment planning process and re-prioritize research and  
 29 development initiatives accordingly.

1 b) Please see table below, for the total subscription costs for EPRI and CEATI over the 2018 to  
2 2021 period.

3

<b>(\$ Millions)</b>	<b>2018 Actual</b>	<b>2019 Actual</b>	<b>2020 Actual</b>	<b>2021 Forecast</b>
<b>Total Subscription Costs</b>	3.7	4.0	3.4	3.7

4

5 c) Hydro One's R&D budget includes specific amounts which benefit each of the Transmission  
6 and Distribution business segment.

7

8 d) Over the 2018 to 2021 period, approximately 63% of actual/forecast RD&D costs are  
9 attributed to EPRI and CEATI subscription costs. It is anticipated that these costs will make up  
10 approximately 45% of the forecast costs in the 2023 test year.

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 066**

2

3 **Reference:**

4 Exhibit E-2-2, Pages 3 and 40

5

6 **Interrogatory:**

7 a) What is the incremental cost of the Joint Security Centre? Please explain what year the full  
8 annual incremental cost is expected to occur. Please divide these costs up into labour and  
9 other costs.

10

11 b) Is this cost captured in the Telecommunications (including cybersecurity line of Appendix 2-  
12 JC?

13

14 **Response:**

15 Please refer to the response in interrogatory E-VECC-063.



Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
Schedule E-VECC-066  
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Witness: MARCOTTE Kevin

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 067**

2

3 **Reference:**

4 Exhibit E-3-2, Page 38

5

6 **Interrogatory:**

7

**Table 16 - Retail Revenue Meters OM&A  
 (\$M)**

8

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Retail Revenue Meters	10.4	10.3	8.9	11.2	11.1	12.2

9

**Table 17 - Wholesale Revenue Meters OM&A  
 (\$M)**

10

11

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Wholesale Revenue Meters	2.3	1.9	2.1	2.2	2.3	2.4

12

13 a) Please explain why retail revenue meter costs increase in 2023 by over 20% since 2018  
 14 whereas wholesale meter costs stay relatively the same over the same period. What is  
 15 different about these two types of metering that result in such different outcomes?

16

17 **Response:**

18 Wholesale Revenue Metering OM&A funds expenditures for maintaining regulatory compliance  
 19 in accordance with the IESO Market Rules as a Meter Services Provider (MSP) for 414 Wholesale  
 20 Revenue Metering Installations (WRMIs). Retail Revenue Metering, on the other hand, funds  
 21 expenditures for: 1) corrective maintenance for approximately 1.4M AMI meters and related  
 22 network equipment (11,000 regional collectors and 40,000 repeaters); 2) managing the sampling  
 23 and reverification programs for both wholesale and retail meters and 3) all activities for  
 24 maintaining regulatory compliance/accreditation (with the exception of IESO Market Rules),  
 25 inventory management, vendor management and administrative support for both wholesale and  
 26 retail meters.

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- 1 The increase in costs from 2018 to 2023 for Retail Metering OM&A was primarily driven by adding
- 2 new staff through consolidating metering expertise from other Lines of Business. These resources
- 3 are not “net new” to the company as they were previously funded under other departments.

Witness: PAISH David

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 068**

2  
3 **Reference:**

4 Exhibit E-3-3, Page 7

5  
6 **Interrogatory:**

7  
8 **Table 5 - Summary of Distribution Standards OM&A (\$M)**

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Distribution Standards Program	0.6	0.2	0.5	1.2	1.4	1.5

9  
10 a) Please provide a list of the inventory of documents ("*standards and guidelines*"). Please also  
11 provide the expected date of revisions for each of the items in the inventory.

12  
13 b) Is all the work on updating these standards and guidelines done internally?

14  
15 **Response:**

16 a) Appendix A includes a listing of Distribution standard, including those which are identified for  
17 revision over the next 5 years.

18  
19 b) No, not all of the labour is associated with internal staff. Over the last five years,  
20 approximately 75% of costs are attributed to internal labour costs.

1  
 2

**Appendix A – Distribution Standards and Revisions identified in next 5 years**

Distribution	2022	2023	2024	2025	2026	2027
CD-14-001						
CD-17-001						
CD-17-002						
CD-17-003						
CD-17-004						
CD-17-005						
CD-60273-001						
CD-62810-001						
CS-62810-001						
CZ-60272-001						
DB-33-001						
DD-20-001						
DD-20-002-Tab0						
DD-20-002-Tab1						
DD-20-003-Tab2				X		
DD-20-004-Tab3		X				
DD-20-005-LOD		X				
DD-20-005-Tab4			X			
DD-20-006-LOD				X		
DD-20-006-Tab5				X		
DD-20-007-LOD			X			
DD-20-007-Tab6			X			
DD-20-008-LOD			X			
DD-20-008-Tab7			X			
DD-20-009-LOD						
DD-20-009-Tab8				X		
DD-20-009-Tab8				X		
DD-20-010-LOD	X					
DD-20-010-Tab9	X					
DD-20-011-Tab10						
DD-20-012-LOD					X	
DD-20-012-Tab11				X		
DD-20-013-LOD	X					
DD-20-013-Tab12	X					

DD-20-014-LOD						
DD-20-014-Tab13						
DD-20-015-LOD					X	
DD-20-015-Tab14			X			
DD-20-016-LOD					X	
DD-20-016-Tab15					X	
DD-20-017-LOD					X	
DD-20-017-Tab16					X	
DD-20-018-LOD					X	
DD-20-018-Tab17					X	
DD-20-019-Tab18						
DD-20-020-LOD						
DD-20-020-Tab19						
DD-20-021-LOD				X		
DD-20-021-Tab20		X				
DD-20-022-LOD					X	
DD-20-022-Tab21				X		
DD-20-023-LOD				X		
DD-20-023-Tab22		X				
DD-20-024-LOD		X				
DD-20-024-Tab23		X				
DD-20-025-LOD					X	
DD-20-025-Tab24		X				
DD-20-025-Tab24		X				
DD-20-026-LOD		X				
DD-20-026-Tab25				X		
DD-20-027-LOD	X					
DD-20-027-Tab26						
DD-20-028-Tab27				X		
DD-20-028-Tab28				X		
DD-21-001						
DD-21-002						
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DD-30-003-Tab2			X			
DD-30-004-LOD			X			
DD-30-004-Tab3			X			
DD-30-005-LOD					X	
DD-30-005-Tab10						
DD-30-005-Tab11						
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DD-30-005-Tab4						
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DD-30-005-Tab6					X	
DD-30-005-Tab7						
DD-30-005-Tab8					X	
DD-30-005-Tab9						
DD-30-006-LOD	X					
DD-30-006-Tab13						
DD-30-006-Tab14						
DD-30-006-Tab15					X	
DD-30-006-Tab16						
DD-30-006-Tab17					X	

DD-30-006-Tab18						
DD-30-006-Tab19						
DD-30-006-Tab20						
DD-30-006-Tab21						
DD-30-007-LOD				X		
DD-30-007-Tab22		X				
DD-30-007-Tab23						
DD-30-007-Tab24		X				
DD-30-007-Tab25						
DD-30-007-Tab26						
DD-30-008-LOD		X				
DD-30-008-Tab27		X				
DD-30-009-Letter						
DD-30-009-LOD	X					
DD-30-009-Tab28	X					
DD-30-010-LOD					X	
DD-30-010-Tab29					X	
DD-30-010-Tab30					X	
DD-30-010-Tab31					X	
DD-30-010-Tab32					X	
DD-30-010-Tab33					X	
DD-30-011-LOD						
DD-30-011-Tab34						
DD-30-011-Tab35						
DD-30-011-Tab36						
DD-30-012-Tab37				X		
DD-30-012-Tab38-39				X		
DD-30a-045	X					
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DD-80-001			X			
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DD-80-004			X			
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DD-83-001			X			
DD-83-002		X				
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DD-83-008		X				
DD-83-009				X		
DD-83-010		X				
DD-83-011		X				
DD-83-012			X			
DD-83-013					X	
DD-84-001						
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DD-84-004		X				
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DD-86-002			X			
DL10-101						
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DP-10-076						
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DP-10-086						
DP-11-101						
DP-11-401						
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DP-21-002						
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DP-21-008						
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DP-21-401						
DP-22-001						
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DP-41-001						
DP-41-002						
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DP-42-001						
DP-42-002						

DP-42-004						
DP-90-001			X			
DP-90-002	X					
DP-90-003	X					
DP-90-004	X					
DP-90-005	X					
DP-90-006	X					
DR-41-001					X	
DR-88-001						
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DS-21-005		X				
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DS-21-012		X				
DS-21-013						
DS-21-014					X	
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DS-24-017						
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DS-24-020				X		
DS-24-021						
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DS-25-002						
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DS-25-004						
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DS-25-008						
DS-26-001				X		
DS-26-002						
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DS-26-006				X		
DS-26-007						
DS-27-001						
DS-27-002						
DS-27-003						
DS-31-001						
DS-31-002				X		
DS-33-001						
DS-33-002						
DS-33-003						
DS-34-001						
DS-34-002						
DS-34-003						
DS-34-004						
DS-34-005			X			
DS-34-006			X			
DS-34-007			X			
DS-36-001						
DS-36-002						
DS-36-003						
DS-36-004						
DS-36-005						
DS-41-001						
DS-41-002					X	
DS-41-003						
DS-41-004						
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DS-41-006						
DS-41-007		X				
DS-41-008				X		
DS-41-010						

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DS-61-018						
DS-61-019						
DS-83-001						
DS-92-001						
DS-92-002						
DT-10-001						
DT-10-002						
DT-10-003						
DT-10-004						
DT-10-005						
DT-10-007						
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DT-10-011						
DT-10-012						
DT-10-015						
DT-10-018						
DT-10-019						
DT-10-020						

DT-10-023						
EM-10-001						
EO-03-001						
GP-65109-001	X					
GR-10-004						
GR-10-006						
LS-23-355						
LS-23-645						
LS-23-646						
LS-23-687						
OD-20-002						
RD-10-001						
RD-10-002						
RD-10-003						
RD-10-004						
RD-11-001			X			
RD-11-002				X		
RD-11-002-LOD				X		
RD-11-003				X		
RD-11-003-LOD				X		
RD-11-004					X	
RD-11-004-LOD					X	
RD-11-005	X					
RD-11-005-LOD				X		
RD-11-006	X					
RD-11-006-LOD				X		
RD-11-007-LOD	X					
RD-11-008				X		
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RD-11-010						
RD-11-011						
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RD-11-014						
RD-11-015						
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1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 069**

2

3 **Reference:**

4 Exhibit E-4-1

5

6 **Interrogatory:**

7

**Table 1 - Summary of Total Common and Other OM&A Costs (\$M)**

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Corporate Functions & Services (CCF&S)	203.4	192.6	183.9	206.5	207.8	214.6
Planning	46.8	40.2	39.5	39.0	41.1	42.5
Information Solutions	125.5	136.2	131.2	137.4	134.9	141.8
Cost of Sales - External Work	18.8	9.0	11.8	10.4	9.3	10.1
Other OM&A	-222.5	-256.1	-195.6	-239.4	-247.4	-203.0
<b>Total<sup>2</sup></b>	<b>172.1</b>	<b>121.9</b>	<b>170.7</b>	<b>153.9</b>	<b>145.8</b>	<b>206.1</b>
<b>Year over Year Change</b>		<b>-29.2%</b>	<b>40.0%</b>	<b>-9.8%</b>	<b>-5.3%</b>	<b>41.4%</b>

8

9 a) Please map the categories in Table 1 above to the associated categories for TX and DX  
 10 Appendix 2-JC - OM&A Programs tables.

11

12 **Response:**

13 a) The referenced table in the preamble of this interrogatory reflects total OM&A, inclusive of  
 14 common costs allocated to other non-regulated segments/affiliates and therefore does not  
 15 directly map to the Transmission and Distribution Appendix 2-JC – OM&A Program tables.  
 16 However, within the same exhibit (E-4-1), common and other OM&A costs allocated to  
 17 Transmission and Distribution are broken down in Tables 2 and 3, respectively, and can be  
 18 mapped accordingly.



1 **Table 2 - Summary of Total Common and Other OM&A Costs Allocated to Transmission (\$M)**

	Test	Tx (E-02-01-01A) – Appendix 2-JC
Description	2023	
	Forecast	
Common Corporate Functions & Services (CCF&S)	96.9	Common Functions and Services
Planning	27.4	Asset Management (Planning) costs
Information Solutions	53.7	Information Technology
Cost of Sales - External Work	5.7	Cost of Sales
Other OM&A	-118.7	Other Recovery
<b>Total</b>	<b>65.0</b>	

2

3 **Table 3 - Summary of Total Common and Other OM&A Costs Allocated to Distribution (\$M)**

	Test	Dx (E-03-01-01A) – Appendix 2-JC
Description	2023	
	Forecast	
Common Corporate Functions & Services (CCF&S)	89.1	Common Functions and Services
Planning	14.9	Asset Management (Planning) Costs
Information Solutions	85.9	Information Technology
Cost of Sales - External Work	4.4	Cost of Sales
Other OM&A	-84.3	Other Recovery
<b>Total</b>	<b>110.0</b>	

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 070**

2

3 **Reference:**

4 Exhibit E-3-4, Page 6

5

6 **Interrogatory:**

7

**Table 4 - Third Party Support OM&A (\$M)**

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Third Party Support P(2)	15.5	15.9	17.6	24.7	23.8	25.0

8

9 a) Please provide the cost of the “new density review program” as well as the business case or  
 10 budget for this program.

11

12 b) What is the incremental cost of the myAccount portal changes in each year beginning 2019  
 13 (using 2018 as the starting point)?

14

15 c) What is the most common complaint about myAccount? How are these concerns being  
 16 addressed over the term of the rate plan?

17

18 **Response:**

19 a) 2022-2027 annual budget for the ongoing support of the density review program are as  
 20 follows. Hydro One was directed to perform this work and as such, there is no business case:

21

Year	2022	2023	2024	2025	2026	2027
Density Review	\$200K	\$200K	\$100K	\$100K	\$100K	\$100K

22

23 b) The OM&A costs for service enhancements that include myAccount are shown in the table  
 24 below.

25

Year	2018	2019	2020	2021	2022	2023
Service Enhancements	\$0.1M	\$0.8M	\$0.7M	\$2.7M	\$2.1M	\$1.6M

- 1 c) Hydro One continuously monitors customer feedback and considers customer comments
- 2 when planning upgrades and enhancements. Today's primary customer complaints relate to
- 3 system performance and limited functionality, and we plan to address these issues.

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 071**

2

3 **Reference:**

4 Exhibit E-3-4

5

6 **Interrogatory:**

7 a) What is the default billing option offered to a new residential account?

8

9 b) Please show how many customers in 2021 are on e-billing and paper billing.

10

11 **Response:**

12 a) All new customers are offered a choice of electronic or paper billing with the vast majority  
13 opting for electronic billing.

14

15 b) As of October 29th, 2021 Hydro One has 678,600 customers, or 48.3%, on e-billing while  
16 725,100 customers, or 51.7%, are receiving paper bills.

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1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 072**

2  
3 **Reference:**

4 Exhibit E-2-2, Pages 3 and 40

5  
6 **Interrogatory:**

7 **Table 6 - Regulatory Compliance (LEAP) OM&A (\$M)**

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Regulatory Compliance (LEAP)	4.4	2.2	0.5	2.5	2.5	2.7

- 8
- 9 a) Is the United Way of Greater Simcoe the only recipient agency of Hydro One LEAP funding?  
10 If yes, does this agency distribute funds for all regions served by Hydro One?
- 11
- 12 b) Please provide the correspondence from the Ontario Energy directing the suspension of LEAP  
13 payments in 2020.
- 14
- 15 c) The LEAP funding in 2018 is particularly high as compared to the required \$1.9 million (0.12%  
16 of approved revenue requirement). Please explain why.
- 17

18 **Response:**

- 19 a) United Way Simcoe Muskoka is the LEAP Lead agency for Hydro One Networks Inc. They  
20 distribute LEAP funds to HONI Customers or use other agencies to do so. All funding is  
21 disbursed through them.
- 22
- 23 b) A key consideration in eligibility for LEAP Emergency Financial Assistance is that the consumer  
24 be disconnected, or be facing disconnection, for non-payment. In its Decision and Order for  
25 Amending Electricity Distributor Licences to Prohibit the Disconnection of Low-volume  
26 Consumers and Related Matters in light of the COVID-19 Pandemic (EB-2020-0109), the OEB  
27 ordered a ban on the disconnection of residential and low volume consumers for non-  
28 payment, which was in effect from March 19, 2020 until July 31, 2020. This ban effectively  
29 suspended the LEAP program for that period. The OEB subsequently issued a communication  
30 in regards to LEAP and the COVID-19 Energy Assistance Program (CEAP). In this  
31 communication, the OEB asked agencies, at this time, to not utilize discretion that is provided  
32 them to consider approving LEAP funds when a consumer is not immediately facing

Witness: GILL Spencer

1           disconnection. The Decision on EB-2020-0109, and the OEB's communication in regards to  
2           LEAP are provided as Attachments 1 and 2, respectively.

3

4       c) In 2018, the demand for the LEAP program by Hydro One customers was particularly high. To  
5       help vulnerable customers pay their bills, Hydro One increased its funding to the LEAP  
6       program by approximately \$2.5 million, as it had done in previous years.



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## **DECISION AND ORDER**

**EB-2020-0109**

### **Amending Electricity Distributor Licences to Prohibit the Disconnection of Low-volume Consumers and Related Matters in light of the COVID-19 Pandemic**

**BY DELEGATION, BEFORE: Brian Hewson**  
Vice President,  
Consumer Protection & Industry Performance

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**March 19, 2020**



## INTRODUCTION AND SUMMARY

The Ontario Energy Board (OEB), of its own motion, has initiated this proceeding to amend the licences of all electricity distributors in light of the current COVID-19 pandemic. As set out in this Decision and Order, the amendments extend the current prohibition against the disconnection of residential customers by reason of non-payment through July 31, 2020; establish a similar prohibition against the disconnection of all other low-volume consumers by reason of non-payment through July 31, 2020; and address related matters.

## BACKGROUND

The OEB's Distribution System Code (DSC) contains a number of rules with which licensed distributors must comply in relation to the disconnection and reconnection of customers for non-payment. Currently, the DSC contains a "disconnection ban" that prohibits disconnection of "occupied residential property" (as those terms are defined in the DSC) for non-payment commencing on November 15<sup>th</sup> in one year and ending on April 30<sup>th</sup> in the following year. Residential customers fall within the group of electricity consumers referred to in the *Ontario Energy Board Act, 1998* (OEB Act) as low-volume consumers. The OEB Act defines low-volume consumer as a consumer who annually uses less than 150,000 kilowatt hours. There is currently no disconnection ban in respect of other electricity consumers (small businesses, for example) that qualify as low-volume consumers.

Section 70 of the OEB Act provides that conditions of a licence may contain provisions that govern a distributor's conduct as it relates to the disconnection of the supply of electricity to a consumer, including the manner in which and the time within which the disconnection takes place or is to take place, and with respect to a low-volume consumer, periods during which the disconnection may not take place. The OEB Act provides that the OEB's regulatory requirements regarding disconnection prevail over anything to the contrary in section 31 of the *Electricity Act, 1998* regarding disconnection for non-payment.

There is currently a great deal of uncertainty as to the severity and duration of the current COVID-19 pandemic. There has already been a significant amount of disruption in the lives and livelihoods of residential and small business electricity customers in Ontario, and the OEB believes that the risk of loss of electricity service on account of arrears should not be an added source of uncertainty at this time.

The OEB understands that a number of electricity distributors have taken measures to voluntarily suspend the disconnection of residential customers beyond the April 30,

2020 end of this year's winter disconnection ban in light of the COVID-19 pandemic. To ensure consistency in the application of the ban on disconnections and related new regulatory requirements across the Province, the licences of all distributors are being amended at this time.

This Decision and Order is being issued by Delegated Authority without a hearing pursuant to section 6(4) of the OEB Act.

## DECISION

The OEB finds it to be in the public interest to amend the licences of all electricity distributors in order to ensure that all low volume consumers (as defined in the OEB Act) are not disconnected for non-payment while Ontario addresses the current COVID-19 pandemic.

The new licence conditions, which are effective immediately, are set out in Attachment A to this Decision and Order. By way of overview:

- i. Until July 31, 2020, no electricity distributor may disconnect a low-volume consumer solely on the grounds of non-payment or issue a disconnection notice to a low-volume consumer solely on the grounds of non-payment. Because the DSC already prohibits the disconnection of residential customers through April 30, 2020, the new licence provision will take effect on May 1, 2020 in respect of residential customers.
- ii. Until July 31, 2020, no electricity distributor may install a load limiting device in respect of a low-volume consumer's premises solely by reason that the customer is in arrears on the payment of their electricity bill. As with disconnections, because the DSC already prohibits the installation of load limiting devices in respect of residential customers' premises through April 30, 2020, the new licence provision will take effect on May 1, 2020.
- iii. Electricity distributors must continue to respect all applicable safety requirements or standards.

During the COVID-19 pandemic and in particular the ban on disconnection of low-volume consumers for non-payment, the OEB also expects distributors to focus efforts on promoting solutions for customers that have arrears, including greater flexibility in payment terms and in offering customers arrears payment agreements (APAs), such as waiving the provisions of section 2.7.8 of the DSC for customers who did not fulfil the

requirements of a previous APA. As well distributors are expected to take steps to increase awareness of assistance or support that may be available through the Low-Income Emergency Assistance Program and the Ontario Electricity Support Program.

The OEB will continue to monitor the situation and may take further steps to protect low-volume electricity consumers as circumstances warrant.

**IT IS ORDERED THAT:**

1. The electricity distribution licence of each electricity distributor be amended to include the conditions set out in Attachment A to this Decision and Order.

**DATED** at Toronto March 19, 2020

**ONTARIO ENERGY BOARD**

*Original Signed By*

Brian Hewson  
Vice President, Consumer Protection & Industry Performance

**Attachment A  
To  
Decision and Order dated March 19, 2020  
EB-2020-0109**

**Licence Conditions**

*Note: The section and paragraph numbers will be revised when integrated into each licence.*

**1. May 1, 2020 – July 31, 2020 – Disconnection and Load Limiter Devices**

1.1 Subject to paragraph 1.3, the Licensee shall not, during the period commencing May 1, 2020 and ending at 11:59 pm on July 31, 2020:

- a) disconnect an occupied residential property solely on the grounds of non-payment;
- b) issue a disconnection notice in respect of an occupied residential property solely on the grounds of non-payment; or
- c) install a load limiter device in respect of an occupied residential property solely on the grounds of non-payment.

Nothing in this paragraph shall preclude the Licensee from (i) disconnecting an occupied residential property in accordance with all applicable regulatory requirements, including the required disconnection notice; or (ii) installing a load limiter device in respect of an occupied residential property, in each case if at the unsolicited request of the customer given in writing on or after May 1, 2020.

1.2 Subject to paragraph 1.7, the Licensee shall not, during the period commencing March 20, 2020 and ending at 11:59 pm on July 31, 2020:

- a) disconnect a property occupied by a customer who is a low-volume consumer other than a residential customer solely on the grounds of non-payment;
- b) issue a disconnection notice in respect of a property occupied by a customer who is a low-volume consumer other than a residential customer solely on the grounds of non-payment; or

- c) install a load limiter device in respect of a property occupied by a customer who is a low-volume consumer other than a residential customer solely on the grounds of non-payment.

Nothing in this paragraph shall preclude the Licensee from (i) disconnecting a property occupied by a customer who is a low-volume consumer other than a residential customer in accordance with all applicable regulatory requirements, including the required disconnection notice; or (ii) installing a load limiter device in respect of a property occupied by a customer who is a low-volume consumer other than a residential customer, in each case if at the unsolicited request of the customer given in writing on or after March 20, 2020.

1.3 Nothing in paragraphs 1.1 to 1.2 shall:

- a) prevent the Licensee from taking such action in respect of an occupied residential property and/or a property occupied by a customer who is a low-volume consumer other than a residential customer as may be required to comply with any applicable and generally acceptable safety requirements or standards; or
- b) require the Licensee to act in a manner contrary to any applicable and generally accepted safety requirements or standards.

1.4 For the purposes of paragraphs 1.1 to 1.3:

“load limiter device” means a device that will allow a customer to run a small number of electrical items in his or her premises at any given time, and if the customer exceeds the limit of the load limiter, then the device will interrupt the power until it is reset; and

“occupied residential property” means an account with the Licensee:

- a) that falls within the residential rate classification as specified in the Licensee’s Rate Order; and
- b) that is inhabited. “property occupied by a customer who is a low-volume consumer other than a residential customer” means an account with the Licensee:
  - a) that falls within the definition of “low-volume consumer” in the Act and is not within a residential rate classification as specified in the Licensee’s Rate Order; andthat has not been permanently vacated.

1.5 Paragraphs 1.1 to 1.4 apply despite any provision of the Distribution System Code to the contrary.



Ontario  
Energy  
Board | Commission  
de l'énergie  
de l'Ontario

May 01, 2020.

BY EMAIL

To: All Electricity Distributors  
All Natural Gas Distributors  
All Unit Sub-meter Providers  
LEAP Lead and Intake Agencies

Re: **LEAP Emergency Financial Assistance and COVID-19 Energy Assistance Program (CEAP)**

On March 25, 2020, the government announced it would be expanding the eligibility of the Low-income Energy Assistance Program to provide direct support in the amount of \$9M to families facing difficulty in paying their electricity and natural gas bills as a result of COVID-19.

The Ontario Energy Board (OEB) is currently working with the Ministry of Energy, Northern Development and Mines (Ministry) in identifying the appropriate structure, eligibility and delivery of the expanded program, which is being referred to as the COVID-19 Energy Assistance Program or CEAP.

To LEAP lead and intake agencies, the OEB and Ministry staff understand the strain on resources the current pandemic may be having on your ability to handle an increase in new clients and requests for assistance, not only for LEAP Emergency Financial Assistance, but for all the other services your agencies provide within your communities. We wanted to take this opportunity to let you know that the OEB and Ministry are discussing how to implement CEAP so that it does not put additional requirements on LEAP agencies during this critical time. We will be providing additional information in the coming weeks on eligibility criteria, program delivery and how and when consumers can apply, including simplifying information requirements and streamlining application processes recognizing the widespread impact of the pandemic.

As you will also be aware, the OEB recently extended the winter disconnection ban to July 31, 2020 for electricity distributors ensuring no one is disconnected for non-payment. Natural gas distributors and many unit sub-meter providers have also announced they will not disconnect for non-payment until July 31<sup>st</sup>. A key consideration in eligibility for LEAP Emergency Financial Assistance is that the consumer be disconnected, or be facing disconnection, for non-payment. While the LEAP Manual does provide discretion for agencies to consider approving LEAP funds when a consumer is not immediately facing disconnection, OEB staff are asking agencies not to utilize that discretion at this time to ensure there are LEAP funds available when the disconnection ban has lifted.

We have also heard from some LEAP agencies that they are currently seeing an increase in calls from COVID-19 impacted individuals who have been referred to the LEAP agency by their utility. In many instances, the individuals do not meet the LEAP criteria and are expressing frustration at the process. Current thinking about the implementation of CEAP is to tie it to end of the disconnection ban, the same timeline for LEAP availability to address these concerns.

We ask that utilities not refer customers to their LEAP agencies for LEAP funding given the extended disconnection ban timelines and in the absence of early agency interventions for consumers who are not facing immediate disconnection. Instead, please provide information about LEAP to your customers and explain that the LEAP agencies are expected to be in position to accept LEAP applications closer to the end of the disconnection ban. This will reduce pressure on agencies' limited operational resources at this time and maximize funds available for when the ban ends.

We thank you in advance for your cooperation and will be in touch as soon as possible with more information on CEAP. If you have any questions related to this letter, please contact Donna Kinapen at [donna.kinapen@oeb.ca](mailto:donna.kinapen@oeb.ca).

Sincerely,

*Original signed by*

Brian Hewson  
Vice President, Consumer Protection & Industry Performance



1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 073**

2  
3 **Reference:**

4 Exhibit E-2-2, Pages 3 and 40

5  
6 **Interrogatory:**

7 **Table 7 - Net Bad Debt OM&A (\$M)**

	Historical			2021	Bridge Year	Test Year
	2018	2019	2020		2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Net Bad Debt	13.6	16.9	31.8	15.4	15.1	18.0

8  
9 a) Leaving aside the anomalous peak pandemic year of 2020 - the three-year average bad debt  
10 amount would be approximately \$15.3M. The evidence on this issue suggests the  
11 incorporation of ongoing pandemic circumstances into the calculation of bad debt in 2023  
12 and beyond. Given the current year's forecast of bad debt is close to the three-year average  
13 (absent 2020) why is 2021 not the better estimate of the bad debt over the period of the rate  
14 plan?

15  
16 **Response:**

17 For 2021 and 2022, there is an estimated \$10M average annual risk to OEB approved NBD  
18 amounts, largely due to sustained economic impacts associated with COVID 19. The 2023 forecast  
19 keeps the level in line with the OEB approved amount from prior proceedings. The \$10M risk,  
20 however, may sustain until economic conditions return to pre-pandemic situation.

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**E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 074**

**Reference:**

Exhibit E-4-2, Page 15

**Interrogatory:**

**Table 7 - Summary of Allocated Human Resources Costs (\$M)**

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
<b>Allocated to Transmission</b>	<b>10.4</b>	<b>10.9</b>	<b>12.4</b>	<b>10.2</b>	<b>11.0</b>	<b>12.4</b>
Change Year over Year		5.1%	14.0%	-17.8%	8.0%	12.3%
<b>Allocated to Distribution</b>	<b>9.7</b>	<b>9.0</b>	<b>9.7</b>	<b>10.0</b>	<b>10.8</b>	<b>12.1</b>
Change Year over Year		-7.1%	7.7%	2.5%	8.0%	12.6%
<b>Allocated to Other</b>	<b>1.4</b>	<b>2.3</b>	<b>1.8</b>	<b>1.6</b>	<b>1.7</b>	<b>1.8</b>
<b>Total</b>	<b>21.5</b>	<b>22.2</b>	<b>23.9</b>	<b>21.7</b>	<b>23.5</b>	<b>26.3</b>

- a) What steps is Hydro One taking to reducing HR costs over the term of the rate plan?
- b) By how much in each year after 2023 are HR costs estimated to be reduced from productivity savings?
- c) What is the allocator of HR costs to the DX and TX operations?

**Response:**

a) Recent benchmarking results from the UMS Group report (Exhibit E-04-02 Attachment 1, page 12) indicate that Hydro One’s Human Resources costs are below the median. Hydro One notes that the company continues to implement changes to control costs. As described in Exhibit E-04-02, Hydro One plans on implementing changes to its core operating model, and moving towards a strategic HR functional model in alignment with most medium-to-large size North American employers. A specific example includes HR’s investments in the HR Payroll Transformation project, that is part of HR2GO, which is anticipated to automate time reporting processes and result in overall savings for Hydro One (see Exhibit B-04-01, Section 4.9, pages 4-5; and ISD G-GP-06).

- 1 b) Savings from all Corporate Costs, which VECC refers to as HR costs, after 2023 will be  
2 calculated relative to a re-baselining of the Productivity Program in connection with  
3 Concentric's (third party) review of the Productivity Framework, as described in SPF Section  
4 1.4.  
5
- 6 c) The methods of allocation for each of HR's five lines of business are outlined in Appendix B of  
7 the Report on Corporate Cost Allocation Review (Exhibit E-04-08 Attachment 1, pages 51 –  
8 52). HR costs by line of business are allocated to the Transmission and Distribution businesses  
9 using the common corporate cost allocation methodology described in section 5.5 of this  
10 report.

**E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 075**

**Reference:**

Exhibit E-2-2, Page 3 and 40

**Interrogatory:**

**Table 8 - Summary of Allocated Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services Costs (\$M)**

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
<b>Allocated to Transmission</b>						
Indigenous Relations	1.0	0.9	0.7	1.8	1.6	1.7
Communications and Stakeholder Relations	3.1	3.1	3.3	4.8	5.0	5.2
Outsourcing Services	0.4	0.4	0.4	0.7	0.7	0.7
<b>Total</b>	<b>4.6</b>	<b>4.5</b>	<b>4.4</b>	<b>7.2</b>	<b>7.3</b>	<b>7.6</b>
<b>Change Year over Year</b>		<b>-2.7%</b>	<b>-0.3%</b>	<b>61.2%</b>	<b>2.4%</b>	<b>3.3%</b>
<b>Allocated to Distribution</b>						
Indigenous Relations	1.7	1.5	1.1	1.3	1.2	1.3
Communications and Stakeholder Relations	5.1	5.3	5.1	5.0	5.3	5.5
Outsourcing Services	0.7	0.7	1.0	0.5	0.6	0.6
<b>Total</b>	<b>7.5</b>	<b>7.5</b>	<b>7.2</b>	<b>6.9</b>	<b>7.1</b>	<b>7.3</b>
<b>Change Year over Year</b>		<b>-0.3%</b>	<b>-3.7%</b>	<b>-4.8%</b>	<b>2.9%</b>	<b>3.1%</b>
<b>Allocated to Other</b>	<b>0.1</b>	<b>0.2</b>	<b>0.2</b>	<b>0.6</b>	<b>0.7</b>	<b>0.7</b>
<b>Total</b>	<b>12.2</b>	<b>12.2</b>	<b>11.9</b>	<b>14.7</b>	<b>15.1</b>	<b>15.6</b>

a) What accounts for the much larger increase since 2018 in “Communications and Stakeholder Relations” allocated to Transmission as compared to that for Distribution?

**Response:**

Allocations between Transmission and Distribution for Communications and Stakeholder Relations have remained stable for 2018-20. For the forecast years, external services associated with corporate communications activities previously allocated to Distribution have been re-evaluated, using the Common Corporate Cost allocation methodology described in Exhibit E-04-08, and are more appropriately split between Transmission and Distribution. Combined with the

Witness: JODOIN Joel

Filed: 2021-11-29  
EB-2021-0110  
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Page 2 of 2

- 1 additional investments from 2020-23 for external services in support of Communications and
- 2 Stakeholder Relations initiatives highlighted in Exhibit E-04-02 (pp. 21-22), this updated allocation
- 3 has contributed to an increase in total forecasted spend allocated to Transmission.

**E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 076**

**Reference:**

Exhibit E-2-2

**Interrogatory:**

**Table 13 - Summary of Allocated Facilities and Real Estate Costs  
 (\$M)**

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
<b>Allocated to Transmission</b>						
Real Estate	7.4	8.6	9.1	7.9	8.4	8.7
Facilities	25.3	26.0	25.3	28.3	28.9	30.0
<b>Total</b>	<b>32.7</b>	<b>34.7</b>	<b>34.3</b>	<b>36.2</b>	<b>37.3</b>	<b>38.7</b>
<b>Change Year over Year</b>		6.1%	-1.0%	5.4%	2.9%	3.8%
<b>Allocated to Distribution</b>						
Real Estate	1.2	1.4	1.0	1.2	1.3	1.3
Facilities	24.0	24.7	24.2	27.8	28.4	29.5
<b>Total</b>	<b>25.2</b>	<b>26.1</b>	<b>25.2</b>	<b>29.0</b>	<b>29.7</b>	<b>30.8</b>
<b>Change Year over Year</b>		3.6%	-3.4%	15.1%	2.3%	3.8%
<b>Allocated to Other</b>	<b>0.0</b>	<b>0.1</b>	<b>0.1</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>
<b>Total</b>	<b>57.9</b>	<b>60.9</b>	<b>59.6</b>	<b>65.3</b>	<b>67.0</b>	<b>69.5</b>

- a) What are the cost drivers explaining the material increase in facilities costs in 2023 as compared to 2018?
- b) What is the cost allocator for this group of costs and why are no Facilities and Real Estate costs allocated to 'Other'?

**Response:**

- a) The cost drivers for 2019 include lease accounting adjustments made to the facility program. In 2020, the material decrease relates to impact from the lease termination of one floor at our Trinity Head Office location. For the following years, please see interrogatory E-Staff-242 part a).

- 1 b) For the cost allocator please refer to E-04-08-01, as the methods of allocation for each line of
- 2 business - including Facilities & Real Estate – are contained in Appendix B. There are indeed
- 3 small amounts of Facilities & Real Estate costs allocated to “Other”; however, they are too
- 4 small to be included in this table, and round to \$0M.



1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 077**

2

3 **Reference:**

4 Exhibit E-4-2, Attachment 1

5

6 **Interrogatory:**

7

**Table 5: Summary of Benchmark Results (2019 Costs)**

Function	Normaliser	Hydro One	1st Quartile	Median	3rd Quartile
Corporate Management	\$M of Revenue	\$2,701	\$1,232	\$2,490	\$4,692
Finance	\$M of Revenue	\$5,777	\$4,472	\$5,777	\$8,371
Real Estate	# of Employees	\$1,150	\$1,205	\$1,983	\$3,630
Human Resources	# of Employees	\$2,612	\$2,601	\$3,226	\$4,538
Legal	\$M of Revenue	\$2,048	\$2,170	\$2,848	\$3,649
Regulatory Affairs	\$M of Revenue	\$1,695	\$1,107	\$1,695	\$2,088
AM Planning	\$M of Net Assets	\$1,598	\$1,529	\$2,749	\$5,774
Corporate Affairs	# of Customers	\$6.2	\$6.0	\$9.4	\$15.2
System Operations	Circuit kM	\$323	\$304	\$321	\$429

8

9 a) Please recast the Table 5 removing the utilities who declined to participate – i.e., Hydro  
 10 Ottawa and Toronto Hydro.

11

12 b) Please explain what exchange rate was used to convert U.S. values into Canadian dollars. How  
 13 does a change in the Cdn-US exchange rate impact the results shown in Table 5?

14

15 **Response:**

16 Response by UMS:

17

18 a) Table 5 has been recast with Hydro Ottawa and Toronto Hydro removed. It has also been  
 19 updated to reflect the correction regarding Corporate Affairs as described in Interrogatory  
 20 Response E-SEC-199(e).

Function	Normalizer	HONI	1st Quartile	Median	3rd Quartile
Corporate Management	\$M of Revenue	\$2,701	\$1,066	\$2,490	\$4,299
Finance	\$M of Revenue	\$5,777	\$4,683	\$5,939	\$9,520
Real Estate	# of Employees	\$1,150	\$1,205	\$1,983	\$3,630
Human Resources	# of Employees	\$2,612	\$2,590	\$2,769	\$4,225
Legal	\$M of Revenue	\$2,048	\$2,199	\$3,067	\$3,881
Regulatory Affairs	\$M of Revenue	\$1,695	\$1,211	\$1,859	\$2,111
AM Planning	\$M of Net T&D Assets	\$1,598	\$1,495	\$2,494	\$6,328
Corporate Affairs	# of Customers	\$8.0	\$6.0	\$9.4	\$14.0
System Operations	Circuit kM	\$323	\$318	\$323	\$456

1  
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 10

b) As discussed on p. 9 of Exhibit E-04-02-01 Attachment 1, an exchange rate of USD:CAD = 1.327 was used to convert U.S. values into Canadian dollars. For functions where the denominator is also in dollars (i.e., revenue or net asset base), a change in exchange rates would have no impact as it would change both the numerator and the denominator proportionally. For the functions where a change in exchange rates would impact the quartiles, the specific results would be dependent on the direction and degree of change. We re-ran the analysis using the 2021 average exchange rate to date of USD:CAD = 1.2506. The result was that the quartile values for the four functions without dollar driven normalizers changed slightly; however, Hydro One’s relative quartile position (i.e., 1<sup>st</sup> quartile, median, 3<sup>rd</sup> quartile) did not change.

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 078**

2

3 **Reference:**

4 Exhibit E-2-2, Page 3 and 40

5

6 **Interrogatory:**

7

8

**Table 3 - Operations Costs Allocated to Distribution (\$M)**

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Operations	20.7	18.4	18.4	23.8	25.9	27.0
Operations Support	14.8	16.4	13.6	14.5	14.2	12.4
HSE	1.8	1.9	1.0	1.3	1.3	1.3
<b>Total Allocated to Distribution</b>	<b>37.3</b>	<b>36.6</b>	<b>33.0</b>	<b>39.7</b>	<b>41.3</b>	<b>40.8</b>

9

10 a) Please confirm that the 'Operations Support' line in Table 3 includes the line 'Smart Grid' in  
 11 Appendix 2-JC DX (i.e., E-03-01-01A\_20210805.XLSX).

12

13 b) Appendix 2-JC shows that 'Smart Grid' spending has declined precipitously since 2018. What  
 14 are the reasons for this?

15

16 **Response:**

17 a) Yes, "Operations Support" includes "Smart Grid" expenditures starting in 2019.

18

19 b) Smart Grid spending has been relatively consistent since 2018 (spending for 2018 was  
 20 \$11.2M and spending for 2023 is planned to be \$9.1M). Up until the end of 2018, the Smart  
 21 Grid was treated as a single pilot program under Distribution Asset Management. Then,  
 22 starting in 2019, the Smart Grid program transitioned into normal business, resulting in  
 23 assigning the main scope of the program to the System Operations line of business. This led  
 24 to splitting the spend between the Distribution Asset Management and System Operations  
 25 Division, with the bulk of the spend allocated to System Operations. The 2023 spend allocated  
 26 to System Operations is \$8.6M and the 2023 spend allocated to Distribution Asset  
 27 Management is \$0.5M.

Filed: 2021-11-29  
EB-2021-0110  
Exhibit I  
Tab 24  
Schedule E-VECC-078  
Page 2 of 2

1

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Witness: HOLDER Godfrey

1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 079**

2

3 **Reference:**

4 Exhibit E-5-1

5

6 **Interrogatory:**

7 a) If Hydro One is a member of the Electricity Distributors Association please provide the annual  
8 fees for 2018 through 2023.

9

10 **Response:**

11 The annual fees provided to the EDA are presented below; please note that Hydro One was not a  
12 member of EDA in 2018.

13

Fees paid (\$M)					
2018	2019	2020	2021	2022	2023
-	0.2	0.2	0.2	0.2	0.2

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1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 080**

2  
3 **Reference:**

4 Exhibit E-5-1, Page 10

5  
6 **Interrogatory:**

7 *“Hydro One opted for a benchmarking review of Inergi fees for*  
8 *the supply chain services SOW. The report was completed*  
9 *October 2020 by Information Services Group Inc. (ISG), an*  
10 *outsourcing advisory firm, retained as an independent third party*  
11 *to undertake the review.”*

- 12  
13 a) If not already in evidence, please provide the referenced benchmarking report.
- 14  
15 b) Was there any termination or penalty costs associated with the ending of the Inergi  
16 Agreement? If so please explain in what year those costs were expensed.

17  
18 **Response:**

- 19 a) Please refer to I-01-E-Staff-248, question (b).
- 20  
21 b) Hydro One did not incur termination or penalty costs upon expiry of the Inergi Agreement for  
22 information technology and supply chain services on February 28, 2021 and October 31, 2021,  
23 respectively. Hydro One does not expect to incur termination or penalty costs upon expiry of  
24 the Inergi Agreement for finance and accounting and payroll services expiring on December  
25 31, 2021.

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1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 081**

2

3 **Reference:**

4 Exhibit E-6-1, Page 18

5

6 **Interrogatory:**

7

8

**Table 1 - Actual and Planned FTEs for 2019 to 2027**

Type	Representation	2019 Actual	2020 Actual	2021 Plan	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan	2027 Plan
Regular	MGT/Non-Represented	613	647	724	760	765	760	760	763	763
	Society	1425	1449	1674	1771	1781	1783	1791	1817	1841
	PWU	3534	3603	3704	3748	3737	3720	3718	3703	3674
	<b>Total Regular</b>	<b>5572</b>	<b>5699</b>	<b>6103</b>	<b>6280</b>	<b>6283</b>	<b>6264</b>	<b>6269</b>	<b>6283</b>	<b>6278</b>
Casual	PWU Hiring Hall	1373	1197	1329	1300	1388	1397	1480	1602	1524
	CUSW	936	948	938	911	912	912	912	912	912
	EPSCA	217	223	198	192	192	192	192	192	192
	LIUNA	272	291	247	237	237	237	237	237	237
	<b>Total Casual</b>	<b>2798</b>	<b>2659</b>	<b>2712</b>	<b>2639</b>	<b>2729</b>	<b>2738</b>	<b>2820</b>	<b>2943</b>	<b>2864</b>
	Temporary	194	152	175	158	159	158	157	157	157
<b>Total</b>		<b>8564</b>	<b>8509</b>	<b>8990</b>	<b>9077</b>	<b>9171</b>	<b>9160</b>	<b>9247</b>	<b>9383</b>	<b>9299</b>

9

10 a) Using Table 1 please show the number of repatriated FTEs in each year (e.g., from Inergi etc.).

11

12 **Response:**

13 a) Please see Interrogatory Response **E-SUP-007**.

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1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 082**

2

3 **Reference:**

4 Exhibit E-6-1, Table 1, Page 18

5 Exhibit E-5-6, Attachment 2B, Table 1

6

7 **Interrogatory:**

8 a) The two tables referenced appear to have slightly different sum totals of FTEs (e.g., 2023 Table  
9 1 FTE's = 9171; whereas 2023 Table 1 Attachment 2B 2023 FTE's are 4,285+4,830 =9,115).

10 Please explain the reasons for the difference in these two presentations.

11

12 **Response:**

13 a) The two tables align with the inclusion of the Shareholder Allocated portion. See Exhibit E-06-  
14 01, Attachment 2A for the (Total Transmission + Distribution + Shareholder Allocated) row.

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1 **E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 083**

2

3 **Reference:**

4 Exhibit E-3-1

5

6 **Interrogatory:**

7 a) What was the incremental operating cost for the Acquired Utilities in each year 2018 through  
8 2023?

9

10 b) Are these amounts included in each presented in Appendix 2-JC (DX)?

11

12 **Response:**

13 a) The table below provides the incremental OM&A costs for the acquired utilities for 2018 to  
14 2022; for 2023 the acquired utilizes are fully integrated and the OM&A is the full OM&A not  
15 incremental.

16

	Incremental OM&A					Fully Integrated OM&A
OMA	2018A	2019A	2020A	2021	2022	2023
Norfolk	2.8	4.1	2.9	3.0	3.8	3.8
Haldimand	3.0	2.8	3.1	5.3	6.0	5.9
Woodstock	1.8	3.6	3.0	2.5	2.7	2.6
<b>Total (\$M)</b>	<b>7.6</b>	<b>10.5</b>	<b>8.9</b>	<b>10.7</b>	<b>12.5</b>	<b>12.2</b>

17

18 b) The above figures are only included in the 2023 values presented in Appendix 2-JC-Dx

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1 **F - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 084**

2  
3 **Reference:**

4 Exhibit F-1-1

5  
6 **Interrogatory:**

7 a) What is Hydro One's current projection of its 2021 regulated ROE for the DX and TX  
8 operations?

9  
10 **Response:**

11 a) Hydro One's revenue requirement for 2021 was approved based on the regulated ROE for Dx  
12 and Tx based the last OEB approved ROE for each of the businesses based on the respective  
13 rebasing years.

14  
15 For Dx, the last approved ROE was for the year 2018 and is applicable for the period from  
16 2018 to 2022, including the year 2021. The Dx regulated ROE is 9.00% as shown on line 5,  
17 page 5 of Exhibit F-01-03.

18  
19 For Tx, the last approved ROE was for the year 2020 and is applicable for the period from 2020  
20 to 2022, including the year 2021. The Tx regulated ROE is 8.52% as shown on line 5, page 6 of  
21 Exhibit F-01-03.

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1 **F - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 085**

2  
3 **Reference:**

4 Exhibit F-1-1

5  
6 **Interrogatory:**

7 *“Hydro One is considering a proposal for a midterm update to the*  
8 *2026 and 2027 cost of capital parameters. Hydro One will*  
9 *indicate prior to the hearing of the Application whether or not it*  
10 *intends to proceed with that proposal. If so, Hydro One would*  
11 *provide information on its updated actual and forecasted debt*  
12 *issuances, the latest economic forecasts then available, as well as*  
13 *its full rationale for requesting the midterm update.”*

- 14  
15 a) Hydro One is required to put a rate plan before the Ontario Energy Board sufficient to provide  
16 notice of that proposal to ratepayers. What is current proposal with respect to a mid-term  
17 update?  
18  
19 b) Please explain when (date by month) the Applicant would be seeking to amend its application  
20 to change its current proposal and what notification to the public of that change it intends to  
21 make of that change.

22  
23 **Response:**

- 24 a) As indicated by the excerpt set out in the preamble, Hydro One provided clear notice of its  
25 intentions in the application. Should Hydro One determine that a request for a mid-term  
26 update to the 2026 and 2027 cost of capital parameters is warranted, it will notify the parties  
27 of the need to amend the application and will provide supporting information at the earliest  
28 opportunity prior to the close of the evidentiary record in this proceeding in accordance with  
29 Rule 11 of the OEB’s Rules of Practice and Procedure.  
30  
31 b) See response to part a) above.

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1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 086**

2  
3 **Reference:**

4 Exhibit G-1-2

5 Exhibit C-7-1, Page 7

6  
7 **Interrogatory:**

8 a) Hydro One is seeking a new Distribution Connection Cost Agreement (CCA) akin to  
9 Transmission CCRA Variance Account. Is Hydro One aware of any other Ontario distribution  
10 utility which has a similar account?

11  
12 b) What is the rationale for Hydro One Distribution to have such an account if other regulated  
13 distributors do not have a similar account? Why is Hydro One different from other LDCs in  
14 Ontario?

15  
16 c) For each of the last 5 years 2016-20 please list the number of Connection Cost Agreements  
17 that required trueing up and the associated amount of the true-up (i.e., show the  
18 materiality of the account had it been in place since 2016). In showing the cost impacts,  
19 please show the load true-up impact separate from any tax impacts.

20  
21 **Response:**

22 a) Yes. Hydro One is aware of Hydro Ottawa's request for a CCRA Payments Differential  
23 Variance Account in its 2021-2025 CIR application (EB-2019-0261), which was accepted by  
24 the OEB last year as part of Hydro Ottawa's approved settlement proposal.

25  
26 b) As noted in response to (a) above, the account being requested would not be the first such  
27 account among Ontario distribution utilities. Moreover, Hydro One notes that other  
28 distributors have sought to address the same issue using different mechanisms. In  
29 particular, a number of other distribution utilities have utilized the OEB's Incremental  
30 Capital Module (ICM) as a means to recover the costs of CCRA true-ups that have materially  
31 impacted the utility, including Alectra for \$5,682,220 in EB-2020-0002 and Newmarket Tay  
32 for \$8,180,100 in EB-2020-0041. These ICM requests were triggered by only two CCRA  
33 contracts (one per utility).

34  
35 Due to Hydro One's geographical diversity and number of customers, as well as recent  
36 economic development in parts of Ontario, Hydro One Transmission has more CCRA's and  
37 Hydro One Distribution is expecting numerous CCAs. As stated in Exhibit C-7-1, page 8,

1 Hydro One Distribution has 14 CCAs downstream attached to one transmission station and  
2 21 CCAs either recently signed or significantly in progress with contracts at other stations.  
3 Furthermore, Hydro One does not view the ICM mechanism, which is only available to  
4 utilities on price cap index for material impacts during the price cap years, as the most  
5 efficient, effective or fair approach for ratepayers as the true ups recorded in the proposed  
6 variance account can be symmetrical, thereby allowing ratepayers to accrue the benefits  
7 from true-ups as the capital contributions received would lower rate base and result in  
8 revenue requirement being returned to rate payers.

9

10 c) As stated in Exhibit C-7-1, page 4, the relevant code amendments did not take effect until  
11 December 2018, so there have been no CCAs requiring true-ups in the years from 2019 to  
12 2020. Load true-ups on these CCAs are scheduled to be performed only after 2022 (3rd year  
13 after in-service for medium-high/low customers). Hydro One has therefore not quantified  
14 the CCAs requiring true-ups over the 2016-2020 period as this information does not exist.  
15 Furthermore, beginning in 2019, downstream CCAs are only at the Initial Economic  
16 Evaluation (IEE) reconciliation stage for actual costs, so it is not expected there is an impact  
17 on revenue requirement or tax expense, as detailed in Interrogatory Response G-Staff-317.

1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 087**

2  
3 **Reference:**

4 Exhibit G-1-2

5 Exhibit C-7-1, Page 7

6  
7 **Preamble:**

8 "The variance account will not include the impact of the Notional Account, section 6.5.7 of the  
9 TSC, prior to the final true up. Notional Accounts do not trigger a payment by Hydro One and  
10 therefore do not adjust rate base nor result in a tax implication. This account will also not  
11 include the impact of the Initial Economic Evaluation (IEE) based upon actual costs as the capital  
12 contributions can be forecasted based on initial customer commitments in their individual  
13 contract and will not trigger an immediate tax obligation as these are collected within the time  
14 frame allowed under the Income Tax Act. For capital contributions collected in accordance with  
15 TSC Section 6.5.2 for the IEE as well as when the transmitter subsequently recalculates the  
16 customer capital contribution based on actual cost, these are individually disclosed for each  
17 project in the relevant Investment Summary Documents. Each of these capital contributions is  
18 an offset to rate base when the asset is placed into service."  
19

20 **Interrogatory:**

21 a) We are unclear how the two adjustments described in above paragraph work. If possible,  
22 please provide an example from a past circumstance showing how entries into the account  
23 would be made. If an actual circumstance is not available please show a theoretical  
24 circumstance showing how the account books entries.  
25

26 **Response:**

27 a) Neither the Actual Cost True Up nor an adjustment to the Notional Account will result in  
28 journal entries as it would not create a regulatory asset nor liability. Please refer to the  
29 response in G-Staff-317 for further information on the impact of Actual Cost True Ups on  
30 revenue requirement.

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1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 088**

2  
3 **Reference:**

4 Exhibit G-1-2, Page 42

5  
6 **Interrogatory:**

7 Hydro One is seeking to establish a new depreciation expense (asset removal) variance account.

- 8  
9 a) Is Hydro One aware of any other Ontario distribution utility with a similar similar account  
10 approved by the OEB?  
11  
12 b) Please show the annual variance that would have been booked into this account had it been  
13 approved at the last distribution cost of service application.  
14

15 **Response:**

- 16 a) Yes, Hydro One is aware that the OEB authorized Toronto Hydro to establish Account 1508 –  
17 Other Regulatory Assets, Subaccount – Derecognition, in its 2015-2019 Custom IR  
18 proceeding (EB-2018-0165) to record the variance between the amount included in rates for  
19 derecognition expense and the actual derecognition expense incurred. Moreover, as stated  
20 in Exhibit G-01-02, p. 43, the account it is requesting for its Distribution business is similar to  
21 the account that the OEB previously approved for its Transmission business.  
22  
23 b) If this account had been approved in the EB-2017-0049 proceeding, the annual variances  
24 that would have been booked into this account are as follows:  
25

\$M	2018	2019	2020	2021 (estimated)	2022 (estimated)
<b>Difference between Actuals and OEB-Approved<sup>1</sup></b>	-8.1	-15.7	-10.8	-14.4	-13.7
<b>Tax Impacts (estimate)<sup>2</sup></b>	-2.9	-5.7	-3.9	-5.2	-4.9
<b>Total Recorded in Variance Account</b>	-11	-21.4	-14.7	-19.6	-18.6

<sup>1</sup> Exhibit E-08-01, Table 2 – Distribution Depreciation Expense

<sup>2</sup> Note that as revenue requirement includes tax, this account should include the tax impact associated with the difference in the asset removal costs.

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Witness: CHHELAVDA Samir



1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 089**

2  
3 **Reference:**

4 Exhibit G-1-1, Attachment 3, Pages 2-4  
5 EB-2016-0160, Exhibit I-12-29 a)  
6 EB-2016-0160, Exhibit I-12-28 f)

7  
8 **Interrogatory:**

- 9 a) Please confirm that the cumulative CDM values in Table 1 only reflect savings due to EE  
10 programs and codes & standards (C&S). If not confirmed, what sources of savings do the  
11 values represent and reconcile with the response to VECC 29 from EB-2016-0160?  
12
- 13 b) In terms of the EE program contribution to the annual values set out in Table 1, are they meant  
14 to reflect: i) both the incremental impact of the CDM programs in the year along with any  
15 (negative) impact due to the loss of persistence of savings achieved in prior years or ii) do they  
16 simply reflect the sum of the annual CDM savings in each year with no allowance for loss of  
17 persistence in savings from previous years' programs.  
18
- 19 c) The Application states that "the difference between the incremental change in actual EE  
20 monthly peak savings and the incremental change in monthly peak amounts assumed in the  
21 approved forecast was used to calculate the revenue impact tracked in the CDM and DR  
22 Variance Account" (emphasis added). According to the response to VECC 28 f) (per EB-2016-  
23 0110), the incremental EE peak savings over 2016 that were included in the forecast for 2018  
24 were 92 MW. Please confirm that this was the case. If not confirmed what was the  
25 incremental amount included in the EB-2016-0110 load forecast for 2018?  
26

27 **Response:**

- 28 a) Yes confirmed.  
29
- 30 b) The annual values set out in Table 1 reflect (i) as stated in the above interrogatory.  
31
- 32 c) No, according to the response to VECC 28 f) (per EB-2016-0110), the incremental EE peak  
33 savings over 2016 that were included in the forecast for 2018 were 90 MW.

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	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>Incremental MW (2018 vs 2016)</b>
<b>EE</b>	1,662	1,575	1,752	90
<b>C&amp;S</b>	505	525	639	134
<b>Total</b>	2,167	2,100	2,391	224

1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 090**

2  
3 **Reference:**

4 Exhibit G-1-1, Attachment 3, Pages 2-4

5  
6 **Preamble:**

7 The Application states that “the difference between the incremental change in actual EE monthly  
8 peak savings and the incremental change in monthly peak amounts assumed in the approved  
9 forecast was used to calculate the revenue impact tracked in the CDM and DR Variance Account”  
10 (emphasis added).

11  
12 **Interrogatory:**

- 13 a) According to the text on page 2 states that Footnote 4 contains a web-link for the sources of  
14 the actual EE savings for 2018 and 2019. However, the link itself is a link to multiple reports  
15 for both 2018 and 2019. Please indicate which specific reports are the sources of the EE  
16 savings for 2018 and 2019. If a single report is the source for each year, please provide the  
17 title and page reference. If multiple sources were used for each year please provide schedules  
18 setting to the derivation of each year’s actual EE savings with reference to the reports  
19 (including page numbers) where each input used can be found.
- 20
- 21 b) Please provide the reports (and associated page numbers) supporting the EE actual 2016 peak  
22 savings used in Table 2. If multiple sources were used for 2016 please provide schedules  
23 setting to the derivation of the year’s actual EE savings with reference to the reports (including  
24 page numbers) where each input used can be found.
- 25
- 26 c) Do the actual EE peak savings for 2016 in Table 2 reflect: i) the EE peak demand impact of  
27 programs implemented in 2016 or ii) the cumulative impact in 2016 of CDM programs  
28 implemented over the period 2006-2016? If the later, does the cumulative impact account  
29 for losses in persistence of savings from EE implemented prior to 2016.
- 30
- 31 d) Do the actual EE peak savings for 2018 in Table 2 reflect: i) the EE peak demand impact of  
32 programs implemented in 2018; ii) the cumulative impact in 2018 of CDM programs  
33 implemented over the period 2016-2018 or iii) the cumulative impact in 2016 of CDM  
34 programs implemented over the period 2006-2018? If either (ii) or (iii), does the cumulative  
35 impact account for losses in persistence of savings from EE implemented prior to 2018?

1 **Response:**

2 a) Attachment 1 (excel file G-VECC-90-01) provides details on the information used in the  
3 analysis. The requested information is shown in Step one of the analysis.

4

5 b) See response to part a) above.

6

7 c) The EE savings for 2016 in the table 2 reflect the cumulative impact in 2016 of CDM programs  
8 implemented over the period 2006-2016. However, the EE amount for 2016 in table 2 is the  
9 difference between the actual peak savings and the peak savings assumed in the approved  
10 forecast. Please refer to Step five in the calculations provided in Attachment 1 to this response  
11 (excel file G-VECC-90-01).

12

13 d) The EE savings for 2018 in the table 2 reflect the cumulative impact in 2018 of CDM programs  
14 implemented over the period 2006-2018. However, the EE amount for 2018 in table 2 is the  
15 difference between the actual peak savings and the peak savings assumed in the approved  
16 forecast. Please refer to Step five in the calculations provided in Attachment 1 (excel file G-  
17 VECC-90-01) to this response.

1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 091**

2  
3 **Reference:**

4 Exhibit G-1-1, Attachment 3, Pages 2-4

5  
6 **Preamble:**

7 The Application states that (page 2)

8  
9 *the difference between the incremental change in actual EE monthly peak savings*  
10 *and the incremental change in monthly peak amounts assumed in the approved*  
11 *forecast was used to calculate the revenue impact tracked in the CDM and DR*  
12 *Variance Account (emphasis added).*

13  
14 **Interrogatory:**

15 The Application also states (page 4):

16  
17 *Consistent with the methodology previously approved by the OEB in calculating*  
18 *the 2017 peak savings amounts, the difference between the forecasted and actual*  
19 *peak savings is the variance amount used for the calculation.*

- 20  
21 a) The calculation in Table 2 simply compares the 2016 actual EE peak savings in 2018 with the  
22 actual saving in 2016. This appears to be inconsistent with the calculation as described in the  
23 Application (per the Preamble) with compares actual vs. forecast savings differences. Please  
24 reconcile and explain how Table 2 capture the difference for 2018 as between the EE peak  
25 savings included in the load forecast and the actual EE peak savings.

26  
27 **Response:**

- 28 a) Please see Step 5 in the attached excel file (G-VECC-090 Attachment 1) for the response to  
29 the interrogatory G-VECC 90. As described in Step 4, the EE peak saving in Table 2 is the  
30 difference of the actual savings and savings assumed in the approved forecast for 2016 and  
31 2018, respectively.

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1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 092**

2

3 **Reference:**

4 Exhibit G-1-1, Attachment 3, Pages 3-4

5

6 **Interrogatory:**

7 a) Pages 3-4 describe the calculation of the actual ICI amounts. Please provide a schedule setting  
8 out the actual calculation for 2018.

9

10 **Response:**

11 a) The detailed calculation to determine the variance due to the ICI program is provided in the  
12 MS Excel file attached to this response (see G-VECC-092 Attachment 1). See Tabs "ICI2018"  
13 and "ICI2019" in the attachment.

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Witness: ALAGHEBAND Bijan



1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 093**

2

3 **Reference:**

4 Exhibit G-1-1, Attachment 3, Page 4

5

6 **Preamble:**

7 The Application states:

8

9 *The IESO provided Hydro One with the information related to the demand*  
10 *measures that were dispatched over the 2016-2019 timeframe. The demand*  
11 *measures include both the dispatchable loads and the resources secured through*  
12 *the demand response auction. The difference between 2018 and 2019 versus 2016*  
13 *is used to calculate the revenue impact tracked in the CDM and DR Variance*  
14 *Account.*

15

16 **Interrogatory:**

17 a) Are the amounts shown for 2016, 2018 and 2019 the amounts actually dispatched in each  
18 month or the amounts under contract that could be dispatched if required?

19

20 **Response:**

21 a) The amounts shown for 2016, 2018 and 2019 are the actual dispatched load in each month.

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Witness: ALAGHEBAND Bijan

1 **G - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 094**

2  
3 **Reference:**

4 Exhibit G-1-4

5  
6 **Interrogatory:**

7 a) Hydro One proposes to dispose of its Distribution credit balance of \$87.7M over 5 years.  
8 While this may mitigate rate impact from the proposed rate increase of the Utility it also  
9 increases intergenerational inequities. For the period 2017 to 2021 (to date). Please  
10 provide the annual number of (1) account closures; (2) Account openings; (3) Account name  
11 changes. For the combined residential classes.

12  
13 b) Based on the current proposal please show the distribution residential rate impacts  
14 (750kWh) if the credit was disposed of over a three-year period.

15  
16 **Response:**

17 a) Please see below for annual customer account openings and closures for combined  
18 residential classes. Account name changes have not been separately tracked and are  
19 counted within accounts opened and closed.<sup>1</sup> Due to the manner in which our tracking  
20 system has been set up, account openings and closures capture total number of  
21 transactions, as we are registering multiple transactions every time an account changes.<sup>2</sup> As  
22 the numbers stated capture the total transactions we are registering, they are not an  
23 accurate reflection of the turnover within our customer base.

24

	2017	2018	2019	2020	2021
<b>Opened</b>	148,313	133,567	129,095	132,255	126,005
<b>Closed</b>	134,454	120,843	118,799	119,609	123,188

25  
26 Hydro One believes that it is in the best interests of ratepayers for Hydro One to dispose of  
27 its regulatory account balances over a period of five years due to the rate smoothing effects  
28 achieved when a large credit balance of \$87.7M offsets revenue requirement over the plan

---

<sup>1</sup> When a name change occurs, a new account is opened and the old account is closed, so that is captured in both account opening and closures.

<sup>2</sup> When a customer moves within Hydro One's service territory, the old account is closed and a new one opened for the same customer. If tenants move in and out of a rental property, the account moves back and forth between tenants and landlord, so multiple transactions are registered in both account openings and closures.

1 term. As noted in Exhibit G-1-4, if the default disposition period of one year were adopted, it  
 2 would result in a large bill decrease in 2023, followed by substantial bill increase in 2024. As  
 3 a result, Hydro One’s proposal to dispose of regulatory balances over the plan term will  
 4 reduce bill fluctuations as compared to disposing over a one year period. Although it is  
 5 standard practice to dispose of regulatory account balances over one year, the OEB has  
 6 previously accepted other distributor’s proposals to spread out the disposition of significant,  
 7 credit DVA balances in order to achieve the effects of bill smoothing.<sup>3</sup>  
 8  
 9 b) Please see table below for distribution rate impacts for residential customers (750kWh) if  
 10 the credit was disposed of over a three-year period based on the balances being proposed  
 11 for disposition.

Rate Class	Monthly Consumption (kWh)	2023		2024		2025		2026		2027	
		Change in Distribution Bill (\$)	Change in Distribution Bill (%)	Change in Distribution Bill (\$)	Change in Distribution Bill (%)	Change in Distribution Bill (\$)	Change in Distribution Bill (%)	Change in Distribution Bill (\$)	Change in Distribution Bill (%)	Change in Distribution Bill (\$)	Change in Distribution Bill (%)
UR	750	-2.39	-6.2%	0.80	2.2%	1.47	4.0%	2.56	6.7%	1.68	4.1%
R1 (without DRP)	750	-2.63	-4.1%	1.49	2.4%	2.51	4.0%	4.06	6.2%	2.40	3.4%
R1 (with DRP)	750	-0.68	-1.8%	0.00	0.0%	0.00	0.0%	0.00	0.0%	0.00	0.0%
R2 (without DRP)	750	-17.93	-21.6%	3.35	5.1%	5.08	7.4%	7.80	10.6%	5.81	7.1%
R2 (with DRP)	750	-0.94	-2.6%	0.00	0.0%	0.00	0.0%	0.00	0.0%	0.00	0.0%
AUR	750	-3.33	-10.3%	1.32	4.6%	1.21	4.0%	2.23	7.1%	1.38	4.1%
AR-Norfolk	750	-4.10	-10.4%	1.60	4.5%	1.47	4.0%	2.51	6.5%	1.68	4.1%
AR-Haldimand	750	-1.87	-5.0%	1.60	4.5%	1.47	4.0%	2.43	6.3%	1.68	4.1%

<sup>3</sup> Please see 2019 IRM Application of Brantford Power, page 15 of 33, and subsequent OEB decision: EB-2018-0020, Decision and Rate Order, Issued December 20, 2018, Revised January 5, 2019, section 6.

1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 095**

2  
3 **Reference:**

4 Exhibit H-1-2, Page 2

5  
6 **Interrogatory:**

7 **Preamble:** The Application states: “A key activity in determining the rates revenue requirement  
8 for each rate pool is the process of grouping similar physical assets owned by Hydro One into  
9 functional categories. The assignment of functional categories is based on the normal system  
10 operating condition of assets in-service as of the end of 2020, with due consideration given to the  
11 OEB Decision in Proceeding EB-2011-0043 in regards to the expanded definition of Network  
12 assets, the electrical system and customer connectivity, and the load forecast data for the 2023  
13 test year”.

- 14  
15 a) Please clarify what is meant by “normal system operating condition”.
- 16  
17 b) Were or are any new Transmission assets (lines and/or stations) placed/forecast to be placed  
18 in service between the end 2020 and the 2023 test year?  
19 i. If yes, please explain the basis on which they are functionalized.

20  
21 **Response:**

- 22 a) Normal system operating condition refers to the “normal operating state”, a defined  
23 operating state of the IESO-controlled grid (ICG).<sup>1</sup>

24  
25 The ICG is in a normal operating state when it meets the following:

- 26 • Fair weather conditions, no adverse weather threatening in the area  
27 • No security limits or thermal limits being exceeded  
28 • Sufficient energy and capacity to meet the forecast demand  
29 • No emerging reliability concerns within Ontario or in neighbouring jurisdictions that  
30 could affect the area

31  
32 The grid is in the normal operating state most of the time.

---

<sup>1</sup> IESO Market Manual 7: System Operations, Part 7.1: IESO-Controlled Grid Operating Procedures, Issue 41.0 (September 15, 2021), section 2.3.2; IESO Training Guide - Communicating with the IESO – Distributor, issued June 2017, Section 4.

- 1 b) The new lines and station transmission assets placed/forecast to be place in service in 2021
- 2 to 2023 are functionalized on the basis of how the assets will be connected to the
- 3 transmission system under normal operating conditions.

1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 096**

2  
3 **Reference:**

4 Exhibit H-1-2, Pages 2-11

5  
6 **Interrogatory:**

7 a) Please confirm that the definition of what are Network Assets, Dual Function Assets, Line  
8 Connection Assets, Transformation Connection Assets, Generation Line and Transformation  
9 Connection Assets and Common Assets has not changed from that used in EB-2019-0082.

10 i. If not confirmed, please explain what the changes are and how they impact the cost  
11 functionalization as shown in Table 2.

12  
13 b) Please confirm that the methodology used to allocate the cost of Dual Function Assets as  
14 between Network and Line Connection has not changed from that used in EB-2019-0082.

15 i. If not confirmed, please explain what the changes are and how they impact the cost  
16 functionalization as shown in Table 2.

17  
18 c) Please confirm that the methodology used to allocate the cost of (shared) Generation Line  
19 and Transformation Connection Assets Dual Function Assets as between Generators and Load  
20 Customers has not changed from that used in EB-2019-0082.

21 i. If not confirmed, please explain what the changes are and how they impact the cost  
22 functionalization as shown in Table 2.

23  
24 **Response:**

25 a) Confirmed.

26 i. Not applicable.

27  
28 b) The methodology used to allocate the cost of Dual Function Lines (“DFLs”) used in HONI’s past  
29 rate applications, most recently EB-2019-0082, was reviewed for this application. It was  
30 determined that the total number of upstream circuits inappropriately divided customer load  
31 between circuits that are not directly supplying the delivery point, which resulted in less load  
32 being associated with the DFL. The updated methodology uses the total number of DFL  
33 circuits that directly supply the delivery point, which reflects the power flow more  
34 appropriately. This review also led to a correction of the data inputs used to allocate  
35 coincident peak for customers that are supplied from circuits with multiple line connection  
36 sections.

Witness: LI Clement

- 1           i. As a result of this improvement in the methodology, some of the costs allocated to the  
2           Network pool shifted to the Line Connection pool for 11 of 182 DFL circuits. The DFL lines  
3           with a material impact due to the data correction are listed in I-H-VECC-100(b). Overall,  
4           the impact of these changes represents less than 0.1% change to the assets in the  
5           Network and Connection pools.  
6
- 7       c) Confirmed.
- 8           i. Not applicable.



1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 097**

2  
3 **Reference:**

4 Exhibit H-1-3, Page 5

5  
6 **Preamble:**

7 The Application states: "This Section provides the annual mid-year net book value and  
8 transmission rates revenue requirement for each of the three rate pools: Network, Line  
9 Connection, and Transformation Connection. For 2023, this is derived using the methodology  
10 described above in Section 2. For the remaining years, 2024 to 2027, the net book value and the  
11 transmission rates revenue requirement have been allocated among the three rate pools using  
12 the same percentage split as 2023".

13  
14 **Interrogatory:**

- 15 a) Please provide a schedule that set out for the years 2024-2027 the net book value of assets  
16 forecast to come into service after 2023.
- 17
- 18 b) With respect to the schedule provided in response to part (a), please provide a breakdown of  
19 the total for each year (2024-2027) as between Network, Line Connection, Transformation  
20 Connection, Common and Other Assets.
- 21
- 22 c) Based on Hydro One's investment plans for 2024-2027, is the assumption that the split of the  
23 net book value and revenue requirement in each of these years will be the same at that in  
24 2023 reasonable and why?

25  
26 **Response:**

- 27 a) The Net book values of transmission assets forecast to come into service after 2023 are not  
28 readily available. As described in Exhibit H, Tab 1, Schedule 2, Gross Book Value (GBV) is the  
29 primary driver to allocate assets to different rate pools. Net book values (NBV) were derived  
30 by assigning the accumulated depreciation to the GBV. The table below shows the Gross Book  
31 Value of Transmission in-service additions for the years 2023 to 2027.

32  
33 **Gross Book Value of Forecasted Total Transmission In-Service Additions**  
34 **(\$ Millions)**

2023	2024	2025	2026	2027
\$1,368.13	\$1,332.44	\$1,710.30	\$1,280.31	\$1,599.79

Witness: LI Clement

- 1 b) The Gross Book Value by functional category is listed below for the years 2023 to 2027. This  
2 is based on normal operating conditions of assets in-service as of the end of 2020.

3  
4  
5

**Gross Book Value of Total Transmission In-Service Additions  
by Functional Category (\$ Millions)**

	<b>Network</b>	<b>Line Connection</b>	<b>Transformation Connection</b>	<b>Common</b>	<b>Other</b>
<b>2023</b>	\$612.05	\$112.34	\$400.46	\$227.84	\$15.44
<b>2024</b>	\$575.99	\$148.73	\$370.09	\$226.93	\$10.70
<b>2025</b>	\$725.27	\$308.46	\$398.46	\$256.94	\$21.17
<b>2026</b>	\$498.99	\$211.61	\$324.39	\$232.30	\$13.02
<b>2027</b>	\$759.60	\$220.46	\$433.10	\$167.84	\$18.77

6  
7  
8  
9  
10

- c) Hydro One believes the assumption that the split of the net book value and revenue requirement in each of these years will be the same as that in 2023 is reasonable because annual ISAs represent only 5% of the total Hydro One transmission GBV, and the 2024-2027 GBV rate pool allocations do not significantly deviate from the 2023 values.

1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 098**

2

3 **Reference:**

4 Exhibit H-2-1

5

6 **Interrogatory:**

7 a) Please provide a schedule that lists the new Transmission Lines that were not included in EB-  
8 2019-0082. In each case, please indicate the relevant project reference number (from this  
9 Application or a previous Application if applicable) that describes the investment, note the  
10 functional category it has been assigned to and indicate why.

11

12 b) Please provide a schedule that lists those Transmission Lines whose functional categorization  
13 has changed from that in EB-2019-0082 and provide an explanation as to the reason for the  
14 change.

15

16 **Response:**

17 a) A list of new transmission line assets that were not included in proceeding EB-2019-0082 is  
18 provided in Table 1 below.

19

20 b) A list of the transmission line assets whose functional category has changed from that in EB-  
21 2019-0082 is provided in Table 2 below.

1

**Table 1 – List of New Transmission Lines**

Operation Designation	Sect.	From	To	Functional Category	Explanation
A3C	9	D3A T#1FHK JCT	Michigan JCT	OTHER	EB-2016-0160 Project S19 Allanburg TS
	10	Michigan JCT	Farr Road JCT	OTHER	EB-2016-0160 Project S19 Allanburg TS
A4CA	1	Gage TS	Gage TS	OTHER	EB-2019-0082 Project SR-02 Gage TS: Station Reinvestment
A4L	15	A4L STR 217 JCT	A.P. Nipigon JCT	LC	EB-2019-0082 Project SR-20 A4L Refurbishment
A6C	5	Crowland TS	Tunnel JCT	LC	Reconfiguration of normal operating system (Circuit previously named C1P)
	10	Tunnel JCT	Vale Inco JCT	LC	Reconfiguration of normal operating system (Circuit previously named C1P)
	11	Vale Inco JCT	Port Colborne TS	LC	Reconfiguration of normal operating system (Circuit previously named C1P)
A6R	8	Riverdale JCT	Overbrook TS	LC	EB-2016-0160 Project D-10 Riverdale Junction to Overbrook TS
B12BL	1	Burlington TS	Dundas #2 JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B12)
	2	Dundas #2 JCT	Horning Mountain JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B12)
	3	Horning Mountain JCT	Newton TS	LC	Reconfiguration of normal operating system (Circuit previously named B12)
	4	Dundas #2 JCT	Dundas TS #2	LC	Reconfiguration of normal operating system (Circuit previously named B12)
	5	Horning Mountain JCT	Alford JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B12)
	6	Alford JCT	Powerline JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B12)
	7	Powerline JCT	Brant TS	DFL	Reconfiguration of normal operating system (Circuit previously named B12)
	8	Powerline JCT	Powerline MTS	LC	Reconfiguration of normal operating system (Circuit previously named B12)
	9	Alford JCT	Mohawk Str 31 EP JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named B12)

Witness: LI Clement

B13BL	1	Burlington TS	Dundas #2 JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B13)
	2	Dundas #2 JCT	Horning Mountain JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B13)
	3	Horning Mountain JCT	Newton TS	LC	Reconfiguration of normal operating system (Circuit previously named B13)
	4	Dundas #2 JCT	Dundas TS #2	LC	Reconfiguration of normal operating system (Circuit previously named B13)
	5	Horning Mountain JCT	Alford JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B13)
	6	Alford JCT	Powerline JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B13)
	7	Powerline JCT	Brant TS	DFL	Reconfiguration of normal operating system (Circuit previously named B13)
	8	Powerline JCT	Powerline MTS	LC	Reconfiguration of normal operating system (Circuit previously named B13)
B2	1	Brant TS	Toyota Woodstock JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B8W)
	2	Toyota Woodstock JCT	Commerce Way JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B8W)
	3	Commerce Way JCT	Commerce Way TS	DFL	Reconfiguration of normal operating system (Circuit previously named B8W)
	4	Commerce Way JCT	Commerce Way TS	DFL	Reconfiguration of normal operating system (Circuit previously named B8W)
	5	Toyota Woodstock JCT	Toyota Woodstock TS	LC	Reconfiguration of normal operating system (Circuit previously named B8W)
B3	12	Horning Mountain JCT	Glanford JCT	LC	EB-2016-0160 Project S68- B3/B4 Line Refurbishment (EB-2016-0160)
	13	Glanford JCT	Mohawk TS	LC	EB-2016-0160 Project S68- B3/B4 Line Refurbishment (EB-2016-0160)
B4	11	M34H T#81 JCT	Nebo JCT	OTHER	EB-2016-0160 Project S68- B3/B4 Line Refurbishment (EB-2016-0160)
	13	Glanford JCT	Mohawk TS	LC	EB-2016-0160 Project S68- B3/B4 Line Refurbishment (EB-2016-0160)

B540TC	1	Bowmanville SS	Clarington JCT	N	Reconfiguration of normal operating system (Circuit previously named B540C)
	2	Clarington JCT	Cherrywood TS	N	Reconfiguration of normal operating system (Circuit previously named B540C)
	3	Clarington JCT	Clarington TS	N	Reconfiguration of normal operating system (Circuit previously named B540C)
C10A	4	Duffin JCT	Seaton JCT	OTHER	EB-2016-0160 Project D17- Seaton MTS: Provide 230 kV Line Connection
	7	Seaton JCT	Seaton MTS	OTHER	EB-2016-0160 Project D17- Seaton MTS: Provide 230 kV Line Connection
C21J	7	Ojibway JCT	Keith TS	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
	8	Romney JCT	Leamington JCT	DFL	EB-2019-0082 Project SS-13 Leamington Area Transmission Reinforcement
C22J	7	Ojibway JCT	Keith TS	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
C2M	1	Pickle Lake SS	C2M T#NB1 JCT	LC	EB-2019-0082 Project SS-02 Wataynikaneyap Line to Pickle Lake Connection
C7BM	5	Manordale JCT	Manordale JCT	OTHER	Database cleanup
D11J	1	Copeland SS	Lower Simcoe St JCT	LC	EB-2014-0140 Project D10: Copeland MTS: Build Line Connection for Toronto Hydro
	2	Lower Simcoe St JCT	John TS	LC	EB-2014-0140 Project D10: Copeland MTS: Build Line Connection for Toronto Hydro
D12J	1	Copeland SS	Lower Simcoe St JCT	LC	EB-2014-0140 Project D10: Copeland MTS: Build Line Connection for Toronto Hydro
	2	Lower Simcoe St JCT	John TS	LC	EB-2014-0140 Project D10: Copeland MTS: Build Line Connection for Toronto Hydro
D3A	13	D3A T#1FHK JCT	Michigan JCT	LC	EB-2016-0160 Project S19 Allanburg TS
D3K	7	Gull Lake South JCT#1	Gull Lake South JCT#2	LC	Database cleanup
E1Q	2	Quirke Lake JCT	Quirke Lake CTS	OTHER	Reconfiguration of normal operating system
E26	5	Holmur JCT	Parry Sound JCT	LC	Generation Connection: Henvey Inlet Wind Farm
	6	Holmur JCT	Holmur CSS	LC	Generation Connection: Henvey Inlet Wind Farm
E27	5	Holmur JCT	Parry Sound JCT	LC	Generation Connection: Henvey Inlet Wind Farm
	6	Holmur JCT	Holmur CSS	LC	Generation Connection: Henvey Inlet Wind Farm

E28	1	Essa TS	Allandale TPS JCT	LC	EB-2019-0082 Project SA-04: Connect Metrolinx Tractions Substations
	2	Allandale TPS JCT	Barrie TS	LC	EB-2019-0082 Project SA-04: Connect Metrolinx Tractions Substations
	3	Allandale TPS JCT	Allandale TPS	LC	EB-2019-0082 Project SA-04: Connect Metrolinx Tractions Substations
E29	1	Essa TS	Allandale TPS JCT	LC	EB-2019-0082 Project SA-04: Connect Metrolinx Tractions Substations
	2	Allandale TPS JCT	Barrie TS	LC	EB-2019-0082 Project SA-04: Connect Metrolinx Tractions Substations
	3	Allandale TPS JCT	Allandale TPS	LC	EB-2019-0082 Project SA-04: Connect Metrolinx Tractions Substations
E34M	11	Cambrian JCT	Cambrian MTS	DFL	EB-2019-0082 Project SS-11 South Nepean Transmission Reinforcement
H10DE	1	Hearn SS	Hearn SS	LC	Reconfiguration of normal operating system (Circuit previously named H10EJ)
	2	Hearn SS	Don Fleet JCT	LC	Reconfiguration of normal operating system (Circuit previously named H10EJ)
	3	Don Fleet JCT	Esplanade TS	LC	Reconfiguration of normal operating system (Circuit previously named H10EJ)
	4	Esplanade TS	Lower Simcoe St JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named H10EJ)
	5	Lower Simcoe St JCT	Copeland SS	OTHER	Reconfiguration of normal operating system (Circuit previously named H10EJ)
H23B	3	Stone Mills JCT	Pancake JCT	DFL	Generation Connection: Stone Mills CGS
	4	Stone Mills JCT	Stone Mills CGS	LC	Generation Connection: Stone Mills CGS
H2CA	1	Gage TS	Gage TS	OTHER	EB-2019-0082 Project SR-02 Gage TS: Station Reinvestment
H75	1	Lakeshore TS	South Middle Road TS	LC	EB-2021-0110 Project T-SA-10 Build Leamington Area Transformer Stations
H76	1	Lakeshore TS	South Middle Road TS	LC	EB-2021-0110 Project T-SA-10 Build Leamington Area Transformer Stations
H82V	6	Holland TS	Holland TS	DFL	EB-2016-0160 Project D07: York Region: Increase Transmission Capability for B82V/B83V Circuits
H83V	6	Holland TS	Holland TS	DFL	EB-2016-0160 Project D07: York Region: Increase Transmission Capability for B82V/B83V Circuits
H9DE	1	Hearn SS	Hearn SS	LC	Reconfiguration of normal operating system (Circuit previously named H9EJ)
	2	Hearn SS	Don Fleet JCT	LC	Reconfiguration of normal operating system (Circuit previously named H9EJ)
	3	Don Fleet JCT	Esplanade TS	LC	Reconfiguration of normal operating system (Circuit previously named H9EJ)
	4	Esplanade TS	Lower Simcoe St JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named H9EJ)
	5	Lower Simcoe St JCT	Copeland SS	OTHER	Reconfiguration of normal operating system (Circuit previously named H9EJ)

Witness: LI Clement

H9K	19	Yellow Falls JCT	Fauquier JCT	DFL	Generation Connection: Yellow Falls CGS
	20	Yellow Falls JCT	Yellow Falls CGS	LC	Generation Connection: Yellow Falls CGS
IDLE31	2	D3A T#8S JCT	D3A T#11S JCT	OTHER	Reconfiguration of normal operating system
J3E	4	Keith TS	Ojibway JCT	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
	5	Ojibway JCT	Crawford JCT	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
J4E	4	Keith TS	Ojibway JCT	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
	5	Ojibway JCT	Crawford JCT	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
J5D	3	McKee JCT	Mid R. JCT Waterman	N	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
K6Z	13	K6Z STR 15 JCT	Pte-Aux-RochesWF JCT	LC	Generation Connection: Pte-Aux-RochesWF CGS
L24A	3	Crysler JCT #2	Hawthorne TS	DFL	Generation Connection: Chrysler CGS
	4	Crysler JCT #2	Crysler CGS	LC	Generation Connection: Chrysler CGS
L5H	7	Mattawa JCT	North Bay TS	DFL	EB-2013-0416 Project D-05 Asset Life Cycle Optimization and Operational Efficiency
	8	Mattawa JCT	Mattawa DS	LC	EB-2013-0416 Project D-05 Asset Life Cycle Optimization and Operational Efficiency
N21W	8	Wanstead JCT	Bostwick Road JCT	DFL	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
	9	Wanstead JCT	Wanstead TS	LC	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
	10	N21W-W42L T22-471 J	N21W T2 JCT	OTHER	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
	11	N21W T2 JCT	Buchanan TS	DFL	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
	12	N21W-W42L T22-471 J	N21W T2 JCT	DFL	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
	13	N21W-W42L T22-471 J	N21W T466 JCT	OTHER	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
N22W	8	Wanstead JCT	Bostwick Road JCT	DFL	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
	9	Wanstead JCT	Wanstead TS	LC	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment

Witness: LI Clement



N25N	1	Nanticoke TS	Nanticoke Solar GS	LC	Generation Connection: Nanticoke Solar GS
NA153M3	1	Holland Marsh JCT	153M3 STR162 JCT	OTHER	Reconfiguration of normal operating system
	3	153M3 STR162 JCT	West Gwillimbry JCT	OTHER	Reconfiguration of normal operating system
P7G	19	Reid JCT	Echo B. Aquarius JCT	OTHER	Reconfiguration of normal operating system
Q6A	3	Beck #1 SS	Q6A T#C JCT	OTHER	Reconfiguration of normal operating system
Q6S	10	Amherst Island JCT	Q6S STR M60 JCT	OTHER	Generation Connection: Amherst Island CGS
	11	Amherst Island JCT	Amherst Island CSS	LC	Generation Connection: Amherst Island CGS
S5M	8	Hillcrest JCT	Nickel Basin JCT	LC	Reconfiguration to accommodate new customer station
	10	Nickel Basin JCT	S5M-S2B T#1 JCT	OTHER	Reconfiguration of normal operating system
S7M	20	Cambrian JCT	Cambrian MTS	LC	EB-2019-0082 Project ISD SS-11 South Nepean Transmission Reinforcement
	21	S7M T#N1 JCT	Fallowfield JCT	LC	EB-2019-0082 Project ISD SS-11 South Nepean Transmission Reinforcement
	22	Fallowfield JCT	Manotick JCT	LC	EB-2019-0082 Project ISD SS-11 South Nepean Transmission Reinforcement
	23	Manotick JCT	S7M STR 20A JCT	LC	EB-2019-0082 Project ISD SS-11 South Nepean Transmission Reinforcement
	24	S7M STR 20A JCT	Manotick STR A40 JCT	LC	EB-2019-0082 Project ISD SS-11 South Nepean Transmission Reinforcement
	25	S7M STR 673N JCT	S7M T#N1 JCT	LC	EB-2019-0082 Project ISD SS-11 South Nepean Transmission Reinforcement
SW-X503E	1	Nobel SS	Nobel SS	N	Reconfiguration of normal operating system
SW-X504E	1	Nobel SS	Nobel SS	N	Reconfiguration of normal operating system
T23C	1	Clarington TS	Wilson JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B23C)
	2	Wilson JCT	Whitby JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B23C)
	3	Whitby JCT	T23C T26C Tie JCT	DFL	Reconfiguration of normal operating system (Circuit previously named B23C)
	4	T23C T26C Tie JCT	Cherrywood TS	DFL	Reconfiguration of normal operating system (Circuit previously named B23C)
	5	Wilson JCT	Wilson TS	LC	Reconfiguration of normal operating system (Circuit previously named B23C)
	6	Whitby JCT	Whitby TS	LC	Reconfiguration of normal operating system (Circuit previously named B23C)
	7	T23C T26C Tie JCT	T23C T26C Tie JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named B23C)
T24C	1	Clarington TS	Columbus JCT	DFL	Reconfiguration of normal operating system (Circuit previously named H24C)
	2	Columbus JCT	Whitby JCT	DFL	Reconfiguration of normal operating system (Circuit previously named H24C)

Witness: LI Clement

	3	Whitby JCT	Cherrywood TS	DFL	Reconfiguration of normal operating system (Circuit previously named H24C)	
	4	Columbus JCT	Lasco JCT	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	5	Lasco JCT	Thornton JCT	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	6	Thornton JCT	Thornton TS	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	7	Thornton JCT	Oshawa G.M. JCT	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	8	Oshawa G.M. JCT	Oshawa G.M. TS	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	9	Lasco JCT	Atlantic Packgng JCT	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	10	Atlantic Packgng JCT	Gerdau A. Whitby CTS	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	11	Atlantic Packgng JCT	Atlantic Packgng CTS	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	12	Oshawa G.M. JCT	G.M.Oshawa JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named H24C)	
	13	Whitby JCT	Whitby TS	LC	Reconfiguration of normal operating system (Circuit previously named H24C)	
	T25B	1	Belleville TS	Pancake JCT	N	Reconfiguration of normal operating system (Circuit previously named B23C)
		2	Pancake JCT	Clarington TS	N	Reconfiguration of normal operating system (Circuit previously named B23C)
T26C	1	Clarington TS	Columbus JCT	DFL	Reconfiguration of normal operating system (Circuit previously named H26C)	
	2	Columbus JCT	Whitby JCT	DFL	Reconfiguration of normal operating system (Circuit previously named H26C)	
	3	Whitby JCT	T23C T26C Tie JCT	DFL	Reconfiguration of normal operating system (Circuit previously named H26C)	
	4	T23C T26C Tie JCT	Cherrywood TS	DFL	Reconfiguration of normal operating system (Circuit previously named H26C)	
	5	Columbus JCT	Lasco JCT	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	
	6	Lasco JCT	Thornton JCT	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	
	7	Thornton JCT	Thornton TS	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	
	8	Thornton JCT	Oshawa G.M. JCT	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	
	9	Oshawa G.M. JCT	Oshawa G.M. TS	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	
	10	Lasco JCT	Atlantic Packgng JCT	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	
	11	Atlantic Packgng JCT	Whitby CGS JCT	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	
	12	Whitby CGS JCT	Gerdau A. Whitby CTS	LC	Reconfiguration of normal operating system (Circuit previously named H26C)	

	13	Atlantic Packgng JCT	Atlantic Packgng CTS	LC	Reconfiguration of normal operating system (Circuit previously named H26C)
	14	Whitby CGS JCT	Whitby CGS	LC	Reconfiguration of normal operating system (Circuit previously named H26C)
	16	Oshawa G.M. JCT	G.M.Oshawa JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named H26C)
	17	Whitby JCT	Whitby TS	LC	Reconfiguration of normal operating system (Circuit previously named H26C)
T28C	3	Seaton JCT	Duffin JCT	N	EB-2016-0160 Project D17- Seaton MTS: Provide 230 kV Line Connection
	4	Seaton JCT	Seaton MTS	LC	EB-2016-0160 Project D17- Seaton MTS: Provide 230 kV Line Connection
T31H	1	Havelock TS	Marine JCT	DFL	Reconfiguration of normal operating system (Circuit previously named H24C)
	2	Marine JCT	Clarington TS	DFL	Reconfiguration of normal operating system (Circuit previously named H24C)
	3	Marine JCT	Otonabee TS	LC	Reconfiguration of normal operating system (Circuit previously named H24C)
T32H	1	Havelock TS	Marine JCT	N	Reconfiguration of normal operating system (Circuit previously named H26C)
	2	Marine JCT	Clarington TS	N	Reconfiguration of normal operating system (Circuit previously named H26C)
UN21-W42	1	N21W-W42L T22-471 J	N21W-W42L T22-471 J	OTHER	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
V71P	12	Grainger South JCT	Vaughan #1 JCT	DFL	EB-2016-0160 GTA North Regional Investment Plan
V75P	19	Grainger North JCT	Richmond Hill JCT	DFL	EB-2016-0160 GTA North Regional Investment Plan
W14	1	Buchanan TS	W14 T#2 JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	2	W14 T#2 JCT	Kettle Creek JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	3	W14 T#2 JCT	Kettle Creek JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	4	Kettle Creek JCT	St.Thomas JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	5	Kettle Creek JCT	St.Thomas JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	6	Kettle Creek JCT	W14 STR B JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)

Witness: LI Clement

	7	Kettle Creek JCT	W14 STR B JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	8	St.Thomas JCT	Lyons JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	9	Lyons JCT	Cranberry JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
	10	Lyons JCT	Lyons JCT	OTHER	Reconfiguration of normal operating system (Circuit previously named W3T and W4T)
W42L	4	N21W T466 JCT	Longwood TS	OTHER	EB-2016-0160 Project S65- N21W/N22W Line Refurbishment
W45LS	4	Buchanan TS	Edgeware TS	LC	Database cleanup
X2Y	11	Chenau TS	Chenau JCT	LC	Reconfiguration of normal operating system
X6	5	Chenau TS	Cobden X6 JCT	LC	Reconfiguration of normal operating system

1

**Table 2 – List of Transmission Lines with Functional Category Changes**

Operation Designation	Sect.	From	To	Functional Category	Functional Category	Explanation
				(EB-2021-0110)	(EB-2019-0082)	
A6C	3	Hurricane JCT	BF Goodrich JCT	LC	OTHER	Reconfiguration of normal operating system
	6	BF Goodrich JCT	Cytec Welland CTS	LC	OTHER	Reconfiguration of normal operating system
	7	BF Goodrich JCT	Oxy Vinyls CTS	LC	OTHER	Reconfiguration of normal operating system
A6C	3	Hurricane JCT	BF Goodrich JCT	OTHER	LC	Reconfiguration of normal operating system
	6	BF Goodrich JCT	Cytec Welland CTS	OTHER	LC	Reconfiguration of normal operating system
	7	BF Goodrich JCT	Oxy Vinyls CTS	OTHER	LC	Reconfiguration of normal operating system
D7V	10	Campbell TS	Speed River JCT	DFL	N	Reconfiguration of normal operating system
	11	Speed River JCT	Cedar TS	DFL	N	Reconfiguration of normal operating system
H2	1	Wiltshire TS	Wiltshire TS	N	DFL	Reconfiguration of normal operating system
H23B	1	Hinchinbrooke SS	Stone Mills JCT	DFL	N	Customer Connection: Stone Mills CGS
H23B	2	Pancake JCT	Belleville TS	DFL	N	Customer Connection: Stone Mills CGS
HIGHFAL2	3	Anjigami JCT	Wawa TS	OTHER	LC	Database cleanup
HLNGWTH1	3	Anjigami JCT #2	Wawa TS	OTHER	LC	Database cleanup
J3E	1	Keith TS	Keith TS	N	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
J4E	1	Keith TS	Keith TS	N	DFL	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
K2Z	8	Tilbury West JCT	Tilbury West JCT	OTHER	LC	Reconfiguration of normal operating system
L24A	1	Raisin River JCT	Crysler JCT #2	DFL	N	Customer Connection: Chrysler CGS
	2	St.Lawrence TS	Raisin River JCT	DFL	N	Customer Connection: Chrysler CGS

Witness: LI Clement

Q26M	1	Beck #2 TS	Abit Cons NAN91 JCT	DFL	LC	EB-2004-0476 - Niagara Reinforcement Project
	2	Abit Cons NAN91 JCT	Crossline JCT	DFL	LC	EB-2004-0476 - Niagara Reinforcement Project
	4	Allanburg West JCT	Middleport TS	DFL	OTHER	EB-2004-0476 - Niagara Reinforcement Project
	6	Crossline JCT	Allanburg West JCT	DFL	OTHER	EB-2004-0476 - Niagara Reinforcement Project
Q35M	1	Beck #2 TS	Abit Cons NAN91 JCT	DFL	LC	EB-2004-0476 - Niagara Reinforcement Project
	2	Abit Cons NAN91 JCT	Crossline JCT	DFL	LC	EB-2004-0476 - Niagara Reinforcement Project
	4	Allanburg West JCT	St.Anns JCT	DFL	OTHER	EB-2004-0476 - Niagara Reinforcement Project
	5	St.Anns JCT	Caledonia Q35M-C9 J	DFL	OTHER	EB-2004-0476 - Niagara Reinforcement Project
	6	Caledonia Q35M-C9 J	Middleport TS	DFL	OTHER	EB-2004-0476 - Niagara Reinforcement Project
	7	Crossline JCT	Allanburg West JCT	DFL	OTHER	EB-2004-0476 - Niagara Reinforcement Project
Q4B	1	Thunder Bay SS	Abitibi JCT	LC	OTHER	Reconfiguration of normal operating system
	2	Abitibi JCT	James Street JCT	LC	OTHER	Reconfiguration of normal operating system
Q6S	7	Invista JCT	Amherst Island JCT	LC	OTHER	Customer Connection: Amherst Island CSS
Q9B	1	Thunder Bay SS	Birch TS	OTHER	LC	Reconfiguration of normal operating system

1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 099**

2

3 **Reference:**

4 Exhibit H-2-2

5

6 **Interrogatory:**

7 a) Please provide a schedule that lists the new Transmission Stations that were not included in  
 8 EB-2019-0082. In each case, please indicate the relevant project reference number (from this  
 9 Application or a previous Application if applicable) that describes the investment, note the  
 10 functional category it has been assigned to and indicate why.

11

12 b) Please provide a schedule that lists those Transmission Stations whose functional  
 13 categorization has changed from that in EB-2019-0082 and provide an explanation as to the  
 14 reason for the change

15

16 **Response:**

17 a) A list of new transmission station assets that were not included in EB-2019-0082 is provided  
 18 in Table 1 below.

19

20 **Table 1 – List of New Transmission Stations**

Station Number	Station Name	Functional Category	Explanation
		(EB-2021-0110)	
1011	Copeland SS	LC	EB-2014-0140 Project D10: Copeland MTS: Build Line Connection for Toronto Hydro
2340	Enfield TS	TC	EB-2016-0160 Project D21: Enfield TS: Build 230/44kV Transformer Station
4215	Caledonia Q35M-C9 J	N,LC	EB-2004-0476 - Niagara Reinforcement Project
7129	Ojibway JCT	LC	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)
7139	Leamington JCT	LC	EB-2016-0160 Project D14: Supply to Essex County Transmission Reinforcement
7143	McKee JCT	LC	EB-2016-0160 Project S81- Gordie Howe International Bridge (GHIB)

Witness: LI Clement

- 1 b) There are no Transmission Stations with a change in functional category from that in EB-2019-
- 2 0082. In preparing the response for this interrogatory, an error was identified in the functional
- 3 category for Station 6192 – Ear Falls TS. This station was incorrectly categorized as LC, TC but
- 4 should have been categorized as N, TC. The impact of this incorrect categorization is
- 5 immaterial (0.01% increase in the network pool and 0.08% decrease in the line connection
- 6 pool).



1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 100**

2  
3 **Reference:**

4 Exhibit H-3-1

5  
6 **Interrogatory:**

- 7 a) Please provide a schedule that lists the new Dual Function Lines that were not included in EB-  
8 2019-0082. In each case, please indicate the relevant project reference number (from this  
9 Application or a previous Application if applicable) that describes the investment, note the  
10 functional categorization percentages it has been assigned and indicate why.
- 11
- 12 b) Please provide a schedule that lists those Dual Function Lines whose functional categorization  
13 percentages have changed from that in EB-2019-008 2 and provide an explanation as to the  
14 reason for the change.

15  
16 **Response:**

- 17 a) All new Dual Function Lines that were not included in EB-2019-0082 have been identified in  
18 H-VECC-98, part (a).
- 19
- 20 b) As described in Exhibit H1, Tab 1, Schedule 2 of the evidence, the allocation factors used to  
21 split the Dual Function Line ("DFL") asset value between Network and Line Connection  
22 functions are derived using the average forecast monthly coincident peak demand of  
23 customer load connected to the DFL and the minimum of the average of summer and winter  
24 transmission capacity of the DFL. Therefore, the allocation might differ from one year to  
25 another due to any change in customer load forecast or due to addition of new DFL lines. The  
26 DFL assets that have had a material change (-/+ 10%) in allocation factor since EB-2019-0082  
27 are listed in the table below. Several of the changes in this table are due to the data correction  
28 noted in H-VECC-096 part (b).

1 **Table 1 – List of Dual Function Lines with Allocation Changes**

Operation Designation	EB-2021-0110		EB-2019-0082		Explanation
	% Network	% Connection	% Network	% Connection	
C2L	85%	15%	62%	38%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
C3L	85%	15%	62%	38%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
E34M	83%	17%	72%	28%	Data correction
K11W	88%	12%	100%	0%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
K12W	88%	12%	100%	0%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
K1W	82%	18%	92%	8%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
K3D	86%	14%	98%	2%	Data correction
K3W	82%	18%	92%	8%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L13W	69%	31%	95%	5%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L14W	83%	17%	96%	4%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L18W	63%	37%	93%	7%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L5H	73%	27%	84%	16%	EB-2013-0416 Project D-05 Asset Life Cycle Optimization and Operational Efficiency
P21R	65%	35%	45%	55%	Data correction
R19TH	58%	42%	45%	55%	Data correction
V41H	67%	33%	47%	53%	Data correction
V42H	67%	33%	38%	62%	Data correction
Z1E	82%	18%	62%	38%	Data correction
Z7E	82%	18%	62%	38%	Data correction

1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 101**

2  
3 **Reference:**

4 Exhibit H-3-2

5  
6 **Interrogatory:**

7 a) Please provide a schedule that lists the new Generator Line Connections that were not  
8 included in EB-2019-0082. In each case, please indicate the relevant project reference  
9 number (from this Application or a previous Application if applicable) that describes the  
10 investment, note the functional categorization percentages it has been assigned and indicate  
11 why.

12  
13 b) Please provide a schedule that lists those Generator Line Connections whose functional  
14 categorization percentages have changed from that in EB-2019-0082 and provide an  
15 explanation as to the reason for the change.

16  
17 **Response:**

18 a) A list of new Generator Line Connections that were not included in EB-2019-0082 is provided  
19 in Table 1 below.

20  
21 b) As described in Exhibit H1, Tab 1, Schedule 2 of the evidence, the allocation of asset value for  
22 Generator Line Connections between "Generators" and "Load" depends on the sum of the  
23 maximum annual non-coincident peak demand of all delivery points connected to the  
24 connection facility and the maximum installed capacity of generation connected to that  
25 facility. Therefore, the allocation might differ from one year to another if there was a change  
26 in the annual non-coincident peak demand or due to connection/disconnection of a  
27 generator. The Generation Line Connections that have had a material change (-/+ 10%) in  
28 allocation factor since EB-2019-0082 are listed in Table 2 below.

1

**Table 1 – List of New Generator Line Connections**

Operation Designation	Sect.	From	To	% Generator	% Load	Explanation
A4L	2	Beardmore JCT	Namewaminikan JCT	41%	59%	Generator was inadvertently omitted in EB-2019-0082
A4L	10	A.P. Nipigon JCT	Beardmore JCT	39%	61%	Generator was inadvertently omitted in EB-2019-0082
A4L	14	Namewaminikan JCT	Namewaminikan CGS	100%	0%	Generator was inadvertently omitted in EB-2019-0082
A4L	15	A4L STR 217 JCT	A.P. Nipigon JCT	72%	28%	Reconfiguration of normal operating system (new line section)
B4V	8	GV3 WF JCT	GV3 WF CGS	100%	0%	Generator was inadvertently omitted in EB-2019-0082
C23Z	10	Belle River JCT #2	Belle River CSS	100%	0%	Generator was inadvertently omitted in EB-2019-0082
C24Z	4	KEPA Wind Farm JCT	Port Alma WF CSS	100%	0%	Generator was inadvertently omitted in EB-2019-0082
D3K	7	Gull Lake South JCT	Gull Lake South JCT	100%	0%	Reconfiguration of normal operating system (new line section)
E26	1	Essa TS	Waubauskene JCT	67%	33%	New Generation Connection: Henvey Inlet Wind Farm
E26	2	Waubauskene JCT	Holmur JCT	67%	33%	New Generation Connection: Henvey Inlet Wind Farm
E26	6	Holmur JCT	Holmur CSS	67%	33%	New Generation Connection: Henvey Inlet Wind Farm
E27	1	Essa TS	Waubauskene JCT	67%	33%	New Generation Connection: Henvey Inlet Wind Farm
E27	2	Waubauskene JCT	Holmur JCT	67%	33%	New Generation Connection: Henvey Inlet Wind Farm
E27	6	Holmur JCT	Holmur CSS	67%	33%	New Generation Connection: Henvey Inlet Wind Farm
H10DE	1	Hearn SS	Hearn SS	43%	57%	Reconfiguration of normal operating system (Circuit previously named H10EJ)
H10DE	2	Hearn SS	Don Fleet JCT	43%	57%	Reconfiguration of normal operating system (Circuit previously named H10EJ)
H10DE	3	Don Fleet JCT	Esplanade TS	43%	57%	Reconfiguration of normal operating system (Circuit previously named H10EJ)
H23B	4	Stone Mills JCT	Stone Mills CGS	100%	0%	New Generation Connection: Stone Mills CGS
H9DE	1	Hearn SS	Hearn SS	43%	57%	Reconfiguration of normal operating system (Circuit previously named H9EJ)
H9DE	2	Hearn SS	Don Fleet JCT	43%	57%	Reconfiguration of normal operating system (Circuit previously named H9EJ)
H9DE	3	Don Fleet JCT	Esplanade TS	43%	57%	Reconfiguration of normal operating system (Circuit previously named H9EJ)
H9K	20	Yellow Falls JCT	Yellow Falls CGS	100%	0%	New Generation Connection: Yellow Falls CGS
L24A	4	Crysler JCT #2	Crysler CGS	100%	0%	New Generation Connection: Chrysler CGS

Witness: LI Clement

L29C	7	North Kent 1 JCT	North Kent 1 CGS	100%	0%	Generator was inadvertently omitted in EB-2019-0082
M2W	9	Williams Mine JCT	Hemlo Mine JCT	21%	79%	Generator was inadvertently omitted in EB-2019-0082
M2W	10	Hemlo Mine JCT	Animki JCT	53%	47%	Generator was inadvertently omitted in EB-2019-0082
M2W	25	Umbata Falls JCT	Williams Mine JCT	21%	79%	Generator was inadvertently omitted in EB-2019-0082
N25N	1	Nanticoke TS	Nanticoke Solar GS	100%	0%	New Generation Connection: Nanticoke Solar GS
Q6S	6	Odessa JCT	Invista JCT	100%	0%	New Generation Connection: Amherst Island CGS
Q6S	7	Invista JCT	Amherst Island JCT	100%	0%	New Generation Connection: Amherst Island CGS
Q6S	11	Amherst Island JCT	Amherst Island CSS	100%	0%	New Generation Connection: Amherst Island CGS
T26C	5	Columbus JCT	Lasco JCT	17%	83%	Reconfiguration of normal operating system (Circuit previously named H26C)
T26C	10	Lasco JCT	Atlantic Packgng JCT	36%	64%	Reconfiguration of normal operating system (Circuit previously named H26C)
T26C	11	Atlantic Packgng JCT	Whitby CGS JCT	40%	60%	Reconfiguration of normal operating system (Circuit previously named H26C)
T26C	14	Whitby CGS JCT	Whitby CGS	100%	0%	Reconfiguration of normal operating system (Circuit previously named H26C)
T28P	1	Wells CGS	Mississagi TS	100%	0%	Generator was inadvertently omitted in EB-2019-0082
T38B	3	Lantz JCT	Trafalgar DESN JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
T38B	4	Hornby JCT	PEC Halton Hills JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
T38B	6	Trafalgar DESN JCT	Hornby JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
T38B	9	PEC Halton Hills JCT	PEC Halton Hills JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
T39B	3	Lantz JCT	Trafalgar DESN JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
T39B	4	Hornby JCT	PEC Halton Hills JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
T39B	6	Trafalgar DESN JCT	Hornby JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
T39B	9	PEC Halton Hills JCT	PEC Halton Hills JCT	66%	34%	Generator was inadvertently omitted in EB-2019-0082
V41H	6	Sithe Goreway JCT	Sithe Goreway JCT	60%	40%	Generator was inadvertently omitted in EB-2019-0082
V41N	4	St.Clair E.C. JCT	St.Clair E.C. CGS	100%	0%	Generator was inadvertently omitted in EB-2019-0082
V42H	7	Sithe Goreway JCT	Sithe Goreway JCT	60%	40%	Generator was inadvertently omitted in EB-2019-0082

Witness: LI Clement

1 **Table 2 – List of Generator Line Connections with Allocation Changes**

Operation Designation	Sect.	From	To	EB-2021-0110		EB-2019-0082		Explanation
				% Generator	% Load	% Generator	% Load	
61M18	1	Seaforth 61M18 JCT	Constance DS	5%	95%	42%	58%	Decreased generation capacity
61M18	2	Constance DS	Goderich TS	7%	93%	51%	49%	Decreased generation capacity
61M18	3	Seaforth TS	Seaforth 61M18 JCT	5%	95%	42%	58%	Decreased generation capacity
B20P	8	Bruce A TS	Bruce HW Plant B TS	47%	53%	100%	0%	Database correction
B24P	8	Bruce A TS	Bruce HW Plant B TS	47%	53%	100%	0%	Database correction
C5E	1	Cecil TS	Terauley TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
C5E	2	Terauley TS	Manhole A OPF	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
C5E	3	Manhole A OPF	Esplanade TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
C7E	1	Cecil TS	Terauley TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
C7E	2	Terauley TS	Manhole A OPF	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
C7E	3	Manhole A OPF	Esplanade TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H11L	1	Hearn SS	Waverly OPF	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H11L	2	Main TS	Lumsden JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H11L	3	Lumsden JCT	Todmorden JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H11L	4	Todmorden JCT	Leaside TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H11L	7	Waverly OPF	Brookside OPF	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS

Witness: LI Clement

H11L	8	Brookside OPF	Main TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H1L	1	Hearn SS	Basin TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H1L	2	Basin TS	Mill Street JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H1L	3	Mill Street JCT	Gerrard TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H1L	4	Gerrard TS	Bloor Street JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H1L	5	Bloor Street JCT	Leaside TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H3L	1	Hearn SS	Basin TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H3L	2	Basin TS	Mill Street JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H3L	3	Mill Street JCT	Gerrard TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H3L	5	Gerrard TS	Bloor Street JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H3L	6	Bloor Street JCT	Leaside TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H3L	9	Gerrard TS	Bloor Street JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H6LC	1	Hearn SS	Don Fleet JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H6LC	2	Gerrard JCT	Bloor Street JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H6LC	3	Bloor Street JCT	Leaside TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H6LC	4	Gerrard JCT	Cecil TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H6LC	5	Don Fleet JCT	Gerrard JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS

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H7L	1	Hearn SS	Waverly OPF	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H7L	2	Main TS	Lumsden JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H7L	3	Lumsden JCT	Todmorden JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H7L	4	Todmorden JCT	Leaside TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H7L	7	Waverly OPF	Brookside OPF	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H7L	8	Brookside OPF	Main TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H8LC	1	Hearn SS	Don Fleet JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H8LC	2	Gerrard JCT	Bloor Street JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H8LC	3	Bloor Street JCT	Leaside TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H8LC	4	Gerrard JCT	Cecil TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
H8LC	5	Don Fleet JCT	Gerrard JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
K2	2	Gull Lake North JCT	Gull Lake North JCT	100%	0%	89%	11%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L12C	1	Leaside TS	Balfour JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L12C	2	Balfour JCT	Charles TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L12C	3	Charles TS	Cecil TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L9C	1	Leaside TS	Balfour JCT	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
L9C	2	Balfour JCT	Charles TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS



L9C	3	Charles TS	Cecil TS	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
M2W	1	Marathon TS	Pic JCT	51%	49%	31%	69%	Increased generation capacity
M2W	2	Pic JCT	Manitouwadge JCT	51%	49%	31%	69%	Increased generation capacity
M2W	6	Manitouwadge JCT	Manitouwadge JCT B	53%	47%	33%	67%	Increased generation capacity
M2W	26	Manitouwadge JCT B	Manitouwadge TS	56%	44%	36%	64%	Increased generation capacity
N6S	1	Sarnia Scott TS	Sarnia Scott JCT	81%	19%	40%	60%	Increased generation capacity
N6S	3	Sarnia Scott JCT	Arlanxeo Can Inc JCT	81%	19%	40%	60%	Increased generation capacity
N6S	4	Arlanxeo Can Inc JCT	TransAlta Energy JCT	81%	19%	40%	60%	Increased generation capacity
N6S	9	TransAlta Energy JCT	TransAlta Energy JCT	81%	19%	40%	60%	Increased generation capacity
N7S	1	Sarnia Scott TS	Sarnia Scott JCT	81%	19%	40%	60%	Increased generation capacity
N7S	2	Sarnia Scott JCT	Arlanxeo Can Inc JCT	81%	19%	40%	60%	Increased generation capacity
N7S	3	Arlanxeo Can Inc JCT	TransAlta Energy JCT	81%	19%	40%	60%	Increased generation capacity
N7S	7	TransAlta Energy JCT	TransAlta Energy JCT	81%	19%	40%	60%	Increased generation capacity
W2S	1	Buchanan TS	Sydenham JCT	49%	51%	31%	69%	EB-2016-0160 Project S50 - Integrated Station Component Replacement - Strathroy TS
W2S	2	Sydenham JCT	Strathroy TS	49%	51%	31%	69%	EB-2016-0160 Project S50 - Integrated Station Component Replacement - Strathroy TS

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1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 102**

2  
3 **Reference:**

4 Exhibit H-03-03

5  
6 **Interrogatory:**

7 a) Please provide a schedule that lists the new Generator Station Connections that were not  
8 included in EB-2019-0082. In each case, please indicate the relevant project reference  
9 number (from this Application or a previous Application if applicable) that describes the  
10 investment, note the functional categorization percentages it has been assigned and indicate  
11 why.

12  
13 b) Please provide a schedule that lists those Generator Station Connections whose functional  
14 categorization percentages have changed from that in EB-2019-0082 and provide an  
15 explanation as to the reason for the change.

16  
17 **Response:**

18 a) A list of new Generator Station Connections that were not included in EB-2019-0082 is  
19 provided in Table 1 below.

20  
21 In preparing the response for this interrogatory, it was discovered that Asset Number 3401 –  
22 Ear Falls TS should not have been listed as a Generator Station as described in H-VECC-99 part  
23 (b).

24  
25 b) Please see response to H-VECC-101 part (b). The Generation Station Connections that have  
26 had a material change (-/+ 10%) in allocation factor since EB-2019-0082 are listed in Table 2  
27 below.

**Table 1 – List of New Generator Station Connections**

Asset Number	Station Name	Functional Category	% Generator	% Load	Explanation
257	Moose Lake TS	TC	97%	3%	Generator was inadvertently omitted in EB-2019-0082
15154	Ojibway JCT	LC	12%	88%	New Generation Connection: Romney CGS

**Table 2 – List of Generator Stations Connections with Allocation Changes**

Asset Number	Station Name	Functional Category	EB-2021-0110		EB-2019-0082		Explanation
			% Generator	% Load	% Generator	% Load	
251	Hamilton Beach TS	LC	48%	52%	32%	68%	Removal of Customer TS
896	Waverly OPF	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
915	Brookside OPF	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
1023	Bloor Street JCT	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
1079	Gerrard JCT	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
1107	Toronto Cecil TS	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
1117	Lumsden JCT	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
1173	Todmorden JCT	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
2047	Goderich TS	TC	7%	93%	51%	49%	Decreased generation capacity
6689	Manitouwadge TS	TC	56%	44%	36%	64%	Increased generation capacity
6952	R.L. Hearn SS	LC	43%	57%	32%	68%	Reconfiguration due to EB-2016-0160 Project D19 Runnymede TS
8211	Bruce HW Plant B TS	TC	47%	53%	100%	0%	Database correction

1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 103**

2

3 **Reference:**

4 Exhibit H-5-1, Page 2

5

6 **Interrogatory:**

7 a) Please explain why it is reasonable to allocate the External Revenues and Regulatory Assets  
8 Balance on the basis of the total revenue requirement split by rate pools.

9

10 **Response:**

11 External Revenues and Regulatory Assets Balance are not associated with specific physical assets  
12 which is the basis of the Hydro One Transmission cost allocation methodology. The allocation of  
13 external revenues and regulatory assets balances are consistent with the allocation of common  
14 and other assets which are also split across all rate pools. This is the same methodology approved  
15 in previous OEB proceedings, and most recently in EB-2019-0082.

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1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 104**

2  
3 **Reference:**

4 Exhibit H-7-1

5 Exhibit D-4-1, Page 17

6  
7 **Interrogatory:**

8 a) Do the forecast values for the Charge Determinants set out in Table 3 (Exhibit D, Tab 4,  
9 Schedule 1) include the load requirements for generators?

10 i. If yes, please confirm that the values in Table 3 are meant to be equal those set out in  
11 Table 1 from Exhibit H, Tab 7, Schedule 1.

12 ii. If not, please confirm that the Charge Determinants set out in Table 1 from Exhibit H, Tab  
13 7, Schedule 1 are equal to the Charge Determinants set out in Table 3 (Exhibit D, Tab 4,  
14 Schedule 1) plus an allowance for the load requirements of generators. Also, please  
15 indicate how these requirements were determined.

16  
17 **Response:**

18 a) Yes

19  
20 i. The charge determinants in Table 1 of Exhibit H, Tab 7, Schedule 1 are total annual values  
21 while those in Table 3 of Exhibit D, Tab 4, Schedule 1 are 12-month average values.  
22 Dividing the values in H-7-1 Table 3 by 12 months yields the Load Forecast after deducting  
23 Embedded Generation and CDM in D-4-1 Table 3.

24  
25 ii. See response in a) i).

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1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 105**

2  
3 **Reference:**

4 Exhibit H-9-1, Page 6

5  
6 **Preamble:**

7 The Application states: "Hydro One's ETS revenue, used for establishing the rates revenue  
8 requirement proposed in this Application, is calculated using the currently approved tariff of  
9 \$1.85/MWh and the three year historical rolling average volume of electricity exported from  
10 Ontario".

11  
12 **Interrogatory:**

- 13 a) Please provide a schedule setting out the historical export volumes for the most recent five  
14 years.
- 15  
16 b) Please provide the export volumes used to determine the forecast annual ETS revenues for  
17 2023 to 2027 and the basis for the "three year rolling average used for each.

18  
19 **Response:**

- 20 a) Table 1 below sets out the historical actual export volumes for the most recent five years.

21  
22 **Table 1- Historical Export Volumes (Actual)**

Year	Export MWh
2016	22,157,981
2017	19,346,599
2018	18,771,464
2019	20,073,511
2020	20,601,892

- 23  
24 b) Table 2 sets out the export volumes used to determine the forecast annual ETS revenues for  
25 2023 to 2027 and shows the basis for the three year rolling average.

1

**Table 2 –Forecast Export Volumes**

<b>Year</b>	<b>Export MWh</b>	<b>Basis of Calculation</b>
2021 (2018- 2020 Avg)	19,815,622	$(18,771,464 + 20,073,511 + 20,601,892)/3$
2022 (2019- 2021 Avg)	20,163,675	$(20,073,511 + 20,601,892 + 19,815,622)/3$
2023 (2020- 2022 Avg)	20,193,730	$(20,601,892 + 19,815,622 + 20,163,675)/3$
2024 (2021- 2023 Avg)	20,057,676	$(19,815,622 + 20,163,675 + 20,193,730)/3$
2025 (2022- 2024 Avg)	20,138,360	$(20,163,675 + 20,193,730 + 20,057,676)/3$

1 **H - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 106**

2  
3 **Reference:**

4 Exhibit H-10-1, Page 1

5  
6 **Preamble:**

7 Table 1 shows the estimated average transmission cost as a percentage of the total bill for a  
8 transmission and a distribution-connected customer.

9  
10 **Interrogatory:**

- 11 a) The Commodity cost included in Table 1 is referred to as the "YTD Weighted Average Rate".  
12 Please explain what is meant by "YTD".  
13 i. If it is not the full year value for 2019, please provide the full year value if it is now  
14 available.
- 15  
16 b) With respect to the Wholesale Transmission Charge in Table 1, is the 1.06 cents/kWh the  
17 average cost of transmission for 2019?  
18 i. Will the value be higher/lower for individual transmission customers based on the load  
19 factor for the customer and whether the customer is charged transformation connection  
20 and/or line connection charges? If yes, is there any estimate available as to the possible  
21 variation?
- 22  
23 c) With respect to the Distribution Service Charges in Table 1, is the 3.02 cents/kWh an average  
24 across all customer classes and all utilities?  
25 i. Will the value be higher/lower for specific customer classes in specific distribution  
26 utilities? If yes, is there any estimate available as to the possible variation?

27  
28 **Response:**

- 29 a) The commodity cost is based on full year 2019.  
30 i. Not applicable.

- 1 b) Yes, the Wholesale Transmission Charge is the average cost of transmission in 2019. It is  
2 calculated by “summing all transmission-related fees paid by all transmission connected  
3 customers in the province, and dividing that sum by the total energy delivered to those  
4 loads”.<sup>1</sup>  
5  
6 i. The IESO states “each customer’s actual fee for transmission service will depend on  
7 many factors such as peak consumption pattern and the types of transmission  
8 services applicable to the customer.”<sup>2</sup> Hydro One does not have an estimate of the  
9 possible variation.  
10  
11 c) Yes, the Distribution Service Charge is an average across all customer classes and utilities.  
12  
13 i. The charge paid by specific classes and specific distribution utilities would vary from  
14 the average. Hydro One does not have an estimate of the possible variation.

---

<sup>1</sup> <https://ieso.ca/en/Power-Data/Monthly-Market-Report>

<sup>2</sup> *ibid.*

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 107**

2  
3 **Reference:**

4 Exhibit L-1-1, Page 2

5 Exhibit L-1-2, Pages 3-4

6 Exhibit L-2-1, Page 18

7 Exhibit L-7-1, Attachment 1, Page 8

8 Exhibit L-7-2, Attachment 1, Page 8

9  
10 **Preamble:**

11 The Application states (L/1/1, page 2): "In this Application, Hydro One proposes to remove the  
12 requirement for Sub-Transmission (ST) customers to own their local transformation from the ST  
13 rate class eligibility requirements. This proposed change responds to customer feedback and is  
14 consistent with other distributors' local transformation options for connecting larger customers."

15  
16 The proposed 2023 ST Tariff Schedule (L/7/2/1/1) describes ST customers as:

17 "This classification applies to either:

- 18 • Embedded supply to Local Distribution Companies (LDCs). "Embedded" meaning  
19 receiving supply via Hydro One Distribution assets, and where Hydro One is the host  
20 distributor to the embedded LDC. Situations where the LDC is supplied via Specific  
21 Facilities are included. OR  
22 • Load which:  
23 ○ is three-phase; and  
24 ○ is connected to and supplied from Hydro One Distribution assets between 44 kV  
25 and 13.8 kV inclusive; and  
26 ○ is greater than 500 kW (monthly measured maximum demand averaged over the  
27 most recent calendar year or whose forecasted monthly average demand over  
28 twelve consecutive months is greater than 500 kW)."

29  
30 The currently approved ST Tariff (L/7/1/1) describes ST customers as:

31 This classification applies to either:

- 32 • Embedded supply to Local Distribution Companies (LDCs). "Embedded" meaning  
33 receiving supply via Hydro One Distribution assets, and where Hydro One is the host  
34 distributor to the embedded LDC. Situations where the LDC is supplied via Specific  
35 Facilities are included. OR  
36 • Load which:  
37 ○ is three-phase; and

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- 1                   ○ is directly connected to and supplied from Hydro One Distribution assets between  
2                   44 kV and 13.8 kV inclusive; the meaning of "directly includes Hydro One not  
3                   owning the local transformation; and  
4                   ○ is greater than 500 kW (monthly measured maximum demand averaged over the  
5                   most recent calendar year or whose forecasted monthly average demand over  
6                   twelve consecutive months is greater than 500 kW)."  
7

8                   **Interrogatory:**

- 9                   a) It is noted that under both definitions a non-embedded distributor ST customer is connected  
10                  to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive. The  
11                  only difference in the definitions appears to be the elimination of "directly" from the new  
12                  description. Please describe more fully the types of local transformation (e.g., high/low  
13                  voltages, proximity to customer, etc.) that Hydro One can own under the new definition (but  
14                  not the old definition) where the customer will now be classified as an ST customer.  
15  
16                  b) Hydro One claims that this revised definition is "and is consistent with other distributors' local  
17                  transformation options for connecting larger customers". Has Hydro One Distribution  
18                  surveyed the customer connection and classification practices of other Ontario electricity  
19                  distributors with large customers served between 44 kV and 13.8 kV and, if yes, what were  
20                  the results in terms of the requirement that the customer own their local transformation?  
21  
22                  c) Please describe the quantity, types and value (NBV or GBV) of "local transformation" assets  
23                  that are included in Hydro One Distribution's proposed revenue requirement for each of the  
24                  years 2023-2027 that are assumed to be associated with service to ST customers based on  
25                  this revised definition. Also, as applicable, please distinguish between assets in-service as of  
26                  December 31, 2022, assets that will be constructed by Hydro One Distribution over the 2023-  
27                  2027 period, and assets that are currently owned by customers but it is assumed Hydro One  
28                  Distribution will purchase over the 2023-2027 period.  
29  
30                  d) Are any of the customers in Hydro One Distribution's General Service classes required to own  
31                  their own local transformation?  
32                    i. If yes, for which customers does this requirement apply?  
33                    ii. If yes, why isn't a similar option being extended to these customers as well?  
34

35                  **Response:**

- 36                  a) Under the current ST rate class definition, a customer can only qualify for the ST rate class if  
37                  the service transformer is owned by the customer. Customer ownership of the service  
38                  transformer is no longer a requirement under the proposed rate class definition.

1 Since non-LDC customers must have an average monthly peak demand greater than 500 kW  
 2 and be connected to Hydro One Distribution assets between 44 kV and 13.8 kV, these  
 3 customers are typically supplied by transformers larger than 500 kVA.

4

5 See table 1 below for the service transformers greater than 500 kVA and between 44 kV to  
 6 13.8 kV primary that Hydro One plans to offer.

7

8

**Table 1 - Planned HONI Standard Service Transformers for ST Rate Class:**

Primary Voltage (V, L-L)	Secondary Voltage (V)	Nameplate Capacity (kVA)
13,800	347/600	1000
25,000	347/600	1000
27,600	347/600	1000, 2000, 3000
44,000	347/600	1000, 2000, 3000

9

10 As with all service transformers, the above transformers must be located in close proximity  
 11 to the end-user due to voltage drop limitations and practical design considerations. These  
 12 transformers will typically be located on the supplied customer's property.

13

14 b) Hydro One informally surveyed the largest Ontario distributors on the maximum service  
 15 transformer sizes that they offer. Based on distributor Conditions of Service posted at the  
 16 time of writing, Alectra and Ottawa Hydro will own 27.6kV-347/600V service transformers up  
 17 to 3000 kVA and 2500 kVA, respectively. It is also Hydro One's understanding that Toronto  
 18 Hydro will own 27.6kV-347/600V service transformers up to 2500 kVA.

19

20 c)

**Table 2 - Estimated Number of Hydro One Service Transformers  
 Serving the ST Rate Class (Incremental by Year)**

21

22

Transformer Capacity	Installed prior to 2023	2023	2024	2025	2026	2027
1000 kVA	24	3	3	3	3	3
2000 kVA	0	1	1	1	1	1
3000 kVA	0	1	1	1	1	1

23

24 Hydro One did not distinguish between assets purchased from customers or those newly  
 25 installed by Hydro One.

1           Please refer to Hydro One's response to VECC IR#127 (I-24-L-VECC-127) for information on  
2           the cost of transformation assets allocated to the ST rate class.

3

4       d) General Service customers are offered standard Hydro One transformation. If a customer  
5       requires non-standard transformation, they are required to provide their own transformation  
6       (e.g. non-standard capacity, voltage, type).

7

8           Hydro One will offer the same standard transformation to both General Service and ST  
9           customer classes, as applicable based on service size and voltage.



1     **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 108**

2

3     **Reference:**

4     Exhibit L-1-2, Page 2

5     Exhibit L-7-1, Attachment 1, Page 7

6

7     **Preamble:**

8     The Application defines the Distributed Generation class as: *“Includes all customers with*  
9     *generation capacity above 10kW”.*

10

11     The Tariff Sheet for the Distributed Generation class states: “This classification applies to an  
12     embedded retail generation facility connected to the distribution system that is not classified as  
13     MicroFIT generation.”

14

15     **Interrogatory:**

16     a) Does the Distributed Generation class only include retail generation facilities (i.e.,  
17     facilities/customers whose primary business is the generation and sale of power)?

18

19     b) Does Hydro One Distribution purchase power from customers/facilities that have behind the  
20     meter generation and whose primary business is not the generation and sale of power?

21

22     c) If yes, how does Hydro One Distribution determine that a customer is a “retail generator”?

23

24     **Response:**

25     a) Yes.

26

27     b) No.

28

29     c) Hydro One follows the definition of “Retail Generator” as provided in the Ontario Energy  
30     Board’s Retail Settlement Code and Distribution System Code.

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1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 109**

2  
3 **Reference:**

4 Exhibit D-5-1, Page 37 (Table E.3)

5 Exhibit L-1-2, Pages 2 and 5

6  
7 **Preamble:**

8 The Application states (L/1/2, page 2): “On an annual basis, Hydro One will create or modify rate  
9 class boundaries for known areas of customer growth and ensure that affected customers are  
10 reclassified accordingly. Outside of the annual review, there is also an opportunity to update the  
11 density boundaries in response to customer inquiries to Hydro One’s call centre”.

12  
13 **Interrogatory:**

14 a) When (i.e., in what month/year) was the rate class boundary review done and the boundaries  
15 revised that established the geographic class boundaries as used for purposes of setting the  
16 2018 rates (per EB-2017-0049)?

17  
18 b) Please provide a schedule that sets out from point in time identified in part (a) to the  
19 preparation of the current Application, each time the rate class geographic boundaries were  
20 revised. As part of the response, please indicate for each revision:

- 21 i. whether it was the result of an annual review or a customer query to the call centre,  
22 ii. what was the net impact of the resulting reclassification of customers on the  
23 customer count for the UR, R1 and R2 classes and  
24 iii. how the new boundary “lines” were determined.

25  
26 c) What was the net impact of these boundary revisions on the customer counts for UR, R1 and  
27 R2 in each of the years 2018 through 2020?

28  
29 d) Do the 2020 customer counts for the UR, R1 and R2 customer classes as set out in Table E.3  
30 fully reflect the results of the most recent boundary review?

31  
32 e) Please provide a break out of the 2020, 2021 and 2022 Seasonal customer count (per Table  
33 E.3) into the three Residential geographic areas (UR, R1 and R2).

34  
35 f) Please for each of the years 2023-2027 please provide a breakdown of the “seasonal  
36 customers” (i.e., those that do not meet the year-round definition) included in each of the  
37 UR, R1 and R2 classes.

- 1 g) Have there been any changes to the geographic Residential customer class boundaries as a  
2 result of either annual reviews or customer inquiries to the call centre since the preparation  
3 of the current Application.  
4 i. If yes, what is the net impact of the resulting reclassification of customers on the customer  
5 count for the UR, R1 and R2 classes?  
6 ii. If yes, has this changed the break-out of Seasonal customers to the UR, R1 and R2 classes  
7 as shown in Table 1 (L/1/2, page 5).  
8  
9 h) When is the next annual boundary review scheduled to take place?

10  
11 **Response:**

12 a) The rate class boundary review that established the boundaries used for purposes of setting  
13 2018 rates (EB-2017-0049) was completed in November 2016.

14  
15 b) Hydro One's GIS does not have the capability to archive and time stamp changes. Therefore,  
16 Hydro One cannot provide all information requested in part B. However, based on other  
17 records, Hydro One can provide the following information:

- 18  
19 • 2017 Q3, 885 customers were moved from Medium density to Urban density (as a  
20 result of municipal query)  
21 ○ 871 R1 customers moved to UR  
22 ○ 11 GSe customers moved to UGe  
23 ○ 3 GSd customers moved to UGd  
24  
25 • 2020 Q4, 7,227 customers were moved to higher density rate classes, 1,505  
26 customers were moved to lower density rate classes (as a result of density-based rate  
27 class boundary review)  
28 ○ 2,698 R2 customers moved to R1  
29 ○ 196 R2 customers moved to UR  
30 ○ 3,806 R1 customers moved to UR  
31 ○ 518 GSe customers moved to UGe  
32 ○ 9 GSd customers moved to UGd  
33 ○ 226 UR customers to R1  
34 ○ 37 UR customers to R2  
35 ○ 1,242 R1 customers to R2  
36

37 Hydro One's density-based rate class boundary review follows the OEB approved process  
38 documented in Exhibit G1-2-1 in EB-2013-0416.

1 c) See response to part b)  
2

3 d) No. Customer counts in Table E.3 are mid-year values. As mentioned in the interrogatory  
4 response to part (b), the most recent boundary review was completed in the later part of  
5 2020, and hence, 2020 customer counts in Table E.3 for the UR, R1 and R2 customer classes  
6 do not reflect the results of this boundary review.  
7

8 e) Table below provides the requested information assuming the percentage split across the  
9 three rate classes based on the most recent rate class boundary review.  
10

	<b>2020</b>	<b>2021</b>	<b>2022</b>
<b>UR</b>	233	232	232
<b>R1</b>	63,955	63,888	63,815
<b>R2</b>	78,938	78,856	78,766

11  
12 f) Table below provides the requested information assuming the percentage split across the  
13 three rate classes based on the most recent rate class boundary review.  
14

	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>
<b>UR</b>	231	230	230	230	229
<b>R1</b>	63,743	63,667	63,579	63,457	63,327
<b>R2</b>	78,677	78,584	78,475	78,325	78,164

15  
16 g) No, there have not been any significant changes to the geographic residential customer class  
17 boundaries since the preparation of the current application.

18 i. Not applicable

19 ii. Not applicable  
20

21 The next annual boundary review is currently in progress and is expected to be completed in  
22 2022.

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1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 110**

2  
3 **Reference:**

4 Exhibit L-1-2, Pages 6-7

5  
6 **Preamble:**

7 The Application states: "Customer density for former Norfolk Power was 25 customers/km of line  
8 (Source: 2014 Yearbook of Electricity Distributors), and it was 12 customers/km of line for former  
9 Haldimand County Hydro (Source: 2015 Yearbook of Electricity Distributors)."

10  
11 **Interrogatory:**

- 12 a) Based on its own GIS system, can Hydro One Distribution provide more update values as to  
13 the customer density for the former Norfolk Power and Haldimand County Hydro? If yes,  
14 please do so.
- 15  
16 b) Please provide a schedule that, using the most recent year for which comparable data is  
17 available, set out for each of Norfolk, Haldimand and Woodstock: i) the OM&A per customer  
18 and iii) NBV of Distribution Assets per customer.

19  
20 **Response:**

- 21 a) Based on the latest information available from Hydro One's GIS, customer density for the  
22 former Norfolk Power and Haldimand County Hydro is 27 customers/km and 13  
23 customers/km, respectively.
- 24  
25 b) Hydro One does not have any more recent data beyond that which is provided in the  
26 yearbooks referenced in the preamble regarding i) OM&A per customer and ii) NBV per  
27 customer that would be comparable to pre-integration values for Norfolk, Haldimand and  
28 Woodstock as stand-alone entities. For ease of reference, Table below provides the  
29 requested information from the referenced Yearbooks.

30

	<b>Norfolk (Source: 2014 Yearbook)</b>	<b>Haldimand (Source: 2015 Yearbook)</b>	<b>Woodstock (Source: 2015 Yearbook)</b>
<b>Number of Customers per km of Line</b>	24.66	12.35	62.61
<b>OM&amp;A per Customer</b>	\$368.79	\$359.86	\$260.00
<b>NBV per Customer</b>	\$2,850.02	\$2,460.78	\$1,749.03

Witness: LI Clement

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Witness: LI Clement



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 111**

2

3 **Reference:**

4 Exhibit D-5-1, Page 37 (Table E.3)

5 Exhibit L-1-3, Attachment 1, Tab I6.2

6

7 **Interrogatory:**

8 a) The 2023 Street Light customer count differs as between Table E.3 (5,494) and Tab I6.2 (CAA-  
9 20,653). Please explain why.

10

11 b) The 2023 Sentinel Light customer count differs as between Table E.3 (19,409) and Tab I6.2  
12 (CAA-9,705). Please explain why.

13

14 **Response:**

15 a) The number in Table E.3 (5,494) is the forecast number of Street Light accounts in 2023,  
16 whereas the number quoted from Tab 6.2 of the cost allocation model (20,653) is the  
17 estimated number of Street Light connections to Hydro One's distribution system.

18

19 b) Please refer to interrogatory response at L-Staff-328 (a).

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1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 112**

2

3 **Reference:**

4 Exhibit D-5-1, Page 37 (Table E.3)

5 Exhibit L-1-3, Attachment 1, Tab I7.1

6

7 **Interrogatory:**

8 a) The 2023 ST customer count differs in Table E.3 (910)) differs from the ST meter count in Tab  
9 I71 (608). Please explain why.

10

11 **Response:**

12 a) Table E.3 provides the total number of ST customer delivery points.

13 L-1-3, Attachment 1, Tab I7.1 provides the number of Hydro One owned meters among ST  
14 customers. Please note that Hydro One does not provide metering facilities to all ST customers,  
15 and some ST delivery points are connected to multiple Hydro One owned meters. This is  
16 described in Exhibit L-2-1 Section 5.2.1.

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1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 113**

2  
3 **Reference:**

4 Exhibit L-1-3, Attachment 1, Pages 4-5  
5 EB-2017-0049, JT 3.18-9 a)

6  
7 **Preamble:**

8 The Application states: "The Services weighting factors, as well as the Billing and Collecting  
9 weighting factors (CAM sheet I5.2), for the six new acquired rate classes, have been established  
10 by adopting values from similar existing Hydro One rate classes. The Services weighting factors  
11 for all Hydro One existing rate classes remain unchanged from the factors used in the 2018 CAM.  
12 These factors reflect an estimate of the relative cost of services assets provided by Hydro One to  
13 its rate classes. The weighting factors for the residential classes are based on an estimated relative  
14 service connection length of 30, 15 and 10 metres for R2, R1 and UR customers, respectively."

15  
16 JT 3.18-9 a) states: "The Services weighting factors are based on an estimated relative service  
17 connection length of 30, 20, 15, and 10 metres for the R2, Seasonal, R1 and UR customers,  
18 respectively, as described in Exhibit G1, Tab 3, Schedule 1 of Hydro One's last distribution  
19 application EB-2013-0416."

20  
21 **Interrogatory:**

- 22 a) Please confirm that assigning Seasonal customers to the UR, R1 and R2 classes does not  
23 change the Services assets used by these customers.  
24  
25 b) If confirmed, why is it appropriate to assume previous Seasonal customers now have a  
26 weighting factor for Services equivalent to the Residential class they are being assigned to?  
27

28 **Response:**

- 29 a) Confirmed.  
30  
31 b) The assumed 20 metre connection length for seasonal customers is only an estimated  
32 weighted amount that reflects the fact that the seasonal class was a mix of customers residing  
33 in low density (R2), medium density (R1) and high density (UR) areas. Once seasonal  
34 customers are split into their respective density based residential classes, it is reasonable to  
35 assume that the seasonal customers share the same service characteristics as other  
36 customers in that class (e.g. a seasonal customer that moves into the R2 class is in a similar  
37 low density area as other R2 customers and therefore is likely to use similar amount of assets).

Witness: LI Clement

- 1 As such, Hydro One believes it is appropriate to apply the weighting factors for the residential
- 2 class that seasonal customers are assigned to.

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 114**

2  
3 **Reference:**

4 Exhibit D-5-1, Page 37 (Table E.3)

5 Exhibit L-1-3, Page 7 and Attachment 1, Tab I7.2

6 EB-2016-0315, Report on Elimination of the Seasonal Class, page 39

7 EB-2017-0049, Exhibit G1-1-3, Attachment 3

8  
9 **Interrogatory:**

10 a) Please explain the basis for the number of manual meter reads in 2023 by rate class as used  
11 in Tab I7.2.

12  
13 b) The Report on the Elimination of the Seasonal Class contained various options regarding the  
14 frequency of meter reading for Seasonal customers after the class was eliminated. What  
15 assumptions are used in the 2023 Cost Allocation model regarding the frequency of meter  
16 reading for Seasonal customers assigned to each of the UR, R1 and R2 classes?

17  
18 c) In the 2018 CAM, what was the weighted average cost of meter reading for each of the UR,  
19 R1, R2 and Seasonal classes?

20  
21 d) In the current 2023 CAM, please confirm that the 2018 CAM weights for the UR, and R2 classes  
22 were also applied to the Seasonal customers assigned to each class.

23 i. If confirmed, please explain why this is appropriate – particularly if the 2018 CAM weight  
24 for Seasonal differed from those used for the other Residential classes.

25  
26 e) Are there costs associated with obtain the readings for meters that are not read manually?

27 i. If not, why not?

28 ii. If yes, in what USOA account(s) are they recorded and what was the total cost for 2020  
29 by USOA?

30  
31 **Response:**

32 a) Scheduled manual meter read forecast is based on the trend in actual historical volumes of  
33 scheduled reads and forecast in customer growth where 5% of these new connects are  
34 assumed to have manual meter reading due to unreliable automated meter reading  
35 capability. In addition, the forecast also accounts for the anticipated degradation in existing  
36 smart meter population due to aging infrastructure and equipment failure.

Witness: LI Clement

1 b) The 2023 Cost Allocation Model assumes status quo meter reading frequency for seasonal  
2 customers moving to UR, R1 and R2 classes. This is consistent with the OEB's decision for the  
3 Elimination of the Seasonal class.<sup>1</sup>

4

5 c) Table below provides the weighted average costs of meter reading per 2018 CAM.

6

<b>UR</b>	1.00
<b>R1</b>	1.25
<b>R2</b>	2.00
<b>Seasonal</b>	2.50

7

8 d) Confirmed.

9 i. As mentioned in the interrogatory response at I-01-L-Staff-326 (d), one of the main  
10 considerations in the development of the meter reading weighting factors was  
11 relative customer density. Since Seasonal customers will be assigned to a year-round  
12 residential rate class based on their respective density, Hydro One believes that it is  
13 appropriate that they adopt the meter reading weighting factors of those year-round  
14 rate class.

15 e) There are no direct costs associated with obtaining readings for meters that are not manually  
16 read.

17 ii. Please refer to interrogatory response at I-01-L-Staff-326 (a).

18 iii. Not applicable.

---

<sup>1</sup> Decision and Order in EB-2020-0246, page 18.



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 115**

2

3 **Reference:**

4 Exhibit L-1-3, Page 7 and Attachment 1, Tab I7.1

5

6 **Interrogatory:**

7 a) Please explain why the smart meter costs are different for the various Residential classes  
8 (including the acquired classes). As part of the response, please explain why for Hydro One  
9 Distribution's existing classes meter costs for R1 are greater than for UR but for the acquired  
10 classes the smart meter cost for AR are less than those for AUR.

11

12 **Response:**

13 a) Please refer to interrogatory response at L-SEC-233.

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1     **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 116**

2

3     **Reference:**

4     Exhibit D-5-1, Page 37 (Table E.3)

5     Exhibit L-1-3, Pages 5-7 and Attachment 1, Tab I5.2

6     EB-2016-0315, Report on Elimination of the Seasonal Class, Page 39

7

8     **Interrogatory:**

9     a) Please explain the basis for the 2023 number of bills by rate class as used in Table 2 (L/1/3,  
10       page 6).

11

12    b) The Report on the Elimination of the Seasonal Class contained various options regarding the  
13       frequency of billing for Seasonal customers after the class was eliminated. What assumptions  
14       are used in the 2023 Cost Allocation model regarding the frequency of billing for Seasonal  
15       customers assigned to each of the UR, R1 and R2 classes?

16

17    **Response:**

18    a) Number of bills shown at the referenced table are based on the assumption that customers  
19       in all rate classes receive 12 bills per year, except for seasonal customers moving UR, R1 and  
20       R2 who are forecasted to receive 4 bills per year.

21

22    b) 2023 Cost Allocation model assumes status quo billing frequency for seasonal customers  
23       assigned to the UR, R1 and R2 classes, that is, they receive 4 bills per year.

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Witness: LI Clement

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 117**

2  
3 **Reference:**

4 Exhibit L-1-3, Page 8

5  
6 **Preamble:**

7 The Application states: "The density factors for all existing density-based rate classes remain  
8 unchanged from the factors used in the 2018 CAM given there have been no material changes to  
9 the relative asset use, maintenance and operation of the distribution system by rate class."  
10

11 **Interrogatory:**

- 12 a) Please explain what is meant by "relative asset use".  
13  
14 b) Please provide the data/analysis that Hydro One Distribution has relied on to make the claim  
15 referenced in the Preamble.  
16  
17 c) Please provide a schedule that sets out the following data for Hydro One Distribution system  
18 for when the original density study was prepared, for when the 2018 CAM was prepared and  
19 for now: i) the total number of customers in each of Hydro One Distribution's density zones,  
20 ii) the number of km of line in each of Hydro One Distribution's density zones, and iii) the  
21 number of customers per km of line in each of the density zones.  
22

23 **Response:**

- 24 a) "Asset Use" refers to the system lay-out and configuration of the Hydro One distribution  
25 system required to serve customers. The term "Relative asset use" refers to the differences  
26 in "asset use" among all the density-based rate classes.  
27  
28 b) Through discussions with distribution planners, Hydro One has determined that there has  
29 been no change in system lay-out and configuration that would impact relative asset use. No  
30 specific analysis was done.  
31  
32 c) As discussed in Hydro One's response to VECC IR#109 part B (L-VECC-109), Hydro One's GIS  
33 does not have the capability to archive and time stamp changes. Therefore, Hydro One cannot  
34 provide the information requested for "when the original density study was prepared" and  
35 "when the 2018 CAM was prepared".

Witness: LI Clement

1           Based on the latest information on Hydro One's GIS system:

2

	<b># of customers</b>	<b>km of line</b>	<b># of customers/circuit km</b>
Low Density Zone	558,326	86,724	6.4
Medium Density Zones	589,967	24,352	24.2
High Density Zones	264,539	4,257	62.1

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 118**

2

3 **Reference:**

4 Exhibit L-1-3, Pages 8-9

5 Exhibit 1-3, Attachment 1, Tab E3

6

7 **Interrogatory:**

8 a) Please provide the equivalent to Tables 7 and 8 based on the 2018 CAM.

9

10 b) With respect to Tables 7, are the 2,543 distribution feeders used to serve all of Hydro One  
11 Distribution's customers, including all of its ST customers?

12

13 c) Please explain why the customer count used in Table 7 does not match the values in Tab E for  
14 either the total number of bulk customers or the total number of primary customers.

15

16 d) With respect to Table 8, how many customers are served from the 526,236 existing  
17 transformers?

18

19 e) Please explain why the customer count used in Table 8 does not match the CCLT total  
20 customer count in Tab E3.

21

22 f) Directionally, which rate classes will be allocated a greater proportion of the revenue  
23 requirement based on the changes in the PLCC values?

24

25 **Response:**

26 a) The requested tables are provided below.

27

**Table 7 - Conductor PLCC (per EB-2017-0049)**

Rating for each distribution feeder circuit, Amps	184
Line-to-Neutral Voltage, kV	4.16
Circuit capacity per distribution feeder, kVA	765
Assumed power factor	80%
Circuit capacity per distribution feeder, kW	612
Number of distribution feeders	2,366
Distribution system Conductors PLCC, kW	1,448,825
Number of customers	1,255,963
<b>PLCC- Conductors (Watts Per Customer)</b>	<b>1,154</b>

Witness: LI Clement

1

**Table 8 - Transformer PLCC (per EB-2017-0049)**

Number of existing transformers	461,450
Capacity (kVA) of Minimum Component	10
Assumed power factor	80%
Distribution system Transformers PLCC, kW	3,691,600
Number of customers	1,255,963
<b>PLCC- Transformers (Watts Per Customer)</b>	<b>2,939</b>

2

3

b) No, 2,543 is the number of primary distribution feeders and they do not serve Hydro One's ST customers.

4

5

6

c) Customer count used in the referenced table match the total customer count as provided in Table E.3 in Exhibit D-05-01 (page 37). Please refer to the interrogatory response at I-01-L-Staff-328 for explanation on differences between customer counts in Table E.3 (Exhibit D-05-01) and bulk customer counts used in the cost allocation model.

7

8

9

10

11

d) All, except approximately 2,600, Hydro One distribution customers are served from the existing 526,236 transformers.

12

13

14

e) Consistent with the original minimum system study, Hydro One has used total customer count in deriving the conductor and transformer PLCC values. Given the small number of customers who are not supplied by Hydro One owned transformers, the impact of using total customer count in deriving Transformer PLCC is expected to be immaterial.

15

16

17

18

19

f) Directionally, higher PLCC values allocate greater portion of the costs to the general service rate classes, as compared to the residential rate classes

20



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 119**

2

3 **Reference:**

4 Exhibit L-1-3, Page 9

5 EB-2017-0049, Exhibit G1-1-3, Attachment 3

6

7 **Interrogatory:**

8 a) Please provide a schedule that compares, for each USOA, the total costs that are directly  
 9 allocated in the current cost allocation model vs. those directly allocated in the 2018 CAM.

10

11 b) Please provide a schedule that compares, for each rate class, the total costs directly allocated  
 12 in the current cost allocation model vs. those directly allocated in the 2018 CAM.

13

14 c) In the 2018 CAM costs were directly allocated to the Sentinel rate class. However, there is no  
 15 direct allocation of cost to the Sentinel class in the 2023 CAM. Please explain why.

16

17 d) If there has been a material change in the relative portion of costs directly allocated to any of  
 18 the other rate classes – please explain why.

19

20 **Response:**

21 a)

22

USoA	5310	5065	5315	5610	5615	5630	5665	TOTAL
Direction Allocation in 2023 CAM in this Application								
	\$ -	\$ 1,964,000	\$ 896,061	\$ 1,039,270	\$ 7,187,008	\$ -	\$ 719,069	\$ 11,805,407
Direction Allocation in 2018 CAM in EB-2017-0049								
TOTAL	\$ 2,017,652	\$ -	\$ 2,666,361	\$ 618,404	\$ 3,873,134	\$ 66,261	\$ 759,852	\$ 10,001,664

Witness: LI Clement

1 b)

Direction Allocation in 2023 CAM in this Application	
GSd	\$2,148,541
UGd	\$671,221
DGEN	\$3,719,561
ST	\$5,007,622
AGSd	\$137,754
AUGd	\$120,708
TOTAL	\$11,805,407

Direction Allocation in 2018 CAM in EB-2017-0049	
GSd	\$2,433,638
UGd	\$742,547
DGEN	\$3,349,392
ST	\$2,738,463
AGSd	\$0
AUGd	\$0
Sen Light	\$737,624
TOTAL	\$10,001,664

2

3 c) The direct allocation to the Sentinel Light rate class in 2018 CAM was related to Sentinel Light  
4 Maintenance Program. This program no longer exists for the following reasons:

5

6 a. Hydro One does not offer new sentinel light connections and removes them when  
7 customer moves out or no longer requires it.

8

9 b. Old high-pressure sodium lights had higher failure rates and required more  
10 maintenance. Most sentinel lights are now LEDs which have longer lifespan and do  
11 not require as much maintenance.

12

13 d) The direct allocation amount assigned to the ST class in this Application is noticeably higher  
14 than in the 2018 CAM because:

15

16 i. The efforts/costs associated with new technologies/industry trends such as energy  
17 storage and behind-the-meter load displacement generation have increased, especially  
18 among ST customers; and

1       ii. The additional settlement efforts/costs associated with ST customers have been reflected  
2           more appropriately in this Application (e.g. complexity of account set up, how multiple  
3           meters are totalized in billing), resulting in a shift of costs from “simple accounts” to  
4           “complex accounts”.

5

6       There is no direct allocation of sentinel light costs in this Application, as explained in part c  
7       above.

8

9       In the 2018 CAM, the rate classes AGSd and AUGd did not exist.

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Witness: LI Clement

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 120**

2  
3 **Reference:**

4 Exhibit L-1-3, Page 3  
5 EB-2017-0049, Exhibit G1-1-3, Attachment 3  
6

7 **Preamble:**

8 The Application states (page 3): "All inputs to the 2023 CAM have been reviewed and updated to  
9 reflect Hydro One's 2023 proposed revenue requirement, charge determinants and updated load  
10 profiles, which are based on the latest hourly metered data results from legacy Hydro One  
11 customers and acquired customers." (emphasis added)  
12

13 The Application also states (page 4): "The Coincident Peak (CP) and Non-coincident Peak (NCP)  
14 inputs to the CAM were updated based on the load forecast established for the "new" UR, R1 and  
15 R2 residential classes that include the seasonal customers. Hydro One's approach ensures that  
16 the CP values for total distribution system remain the same before and after seasonal  
17 elimination."  
18

19 **Interrogatory:**

- 20 a) What was the basis for the updated load profiles (e.g., what years of hourly data were used  
21 and how were the data/results weather normalized)?  
22  
23 b) If hourly data was not available for all customers in all customer classes, how were the load  
24 profiles established?  
25  
26 c) Please provide the 12CP and 4NCP values for the UR, R1, R2 and Seasonal classes for 2023  
27 assuming the Seasonal class was not eliminated.  
28

29 **Response:**

- 30 a) Please refer to Hydro One's response to Staff IR #323 (L-Staff-323).  
31  
32 b) Aggregate hourly load profile for available data in each rate class was scaled to be consistent  
33 with the annual forecast for that rate class.

1 c) Table below provides the requested information.

2

<b>Rate Class</b>	<b>12CP</b>	<b>4 NCP</b>
<b>UR</b>	4,666,828	1,984,659
<b>R1</b>	10,815,669	4,277,633
<b>R2</b>	9,945,003	4,008,578
<b>Seasonal</b>	1,121,189	611,927

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 121**

2

3 **Reference:**

4 Exhibit L-2-1, Page 4

5

6 **Preamble:**

7 The Application states: "Hydro One's development of distribution rates for this application  
8 follows generally accepted ratemaking principles".

9

10 **Interrogatory:**

11 a) Please indicate how considerations regarding "efficiency" were taken into account in the  
12 development of the distribution rates.

13

14 **Response:**

15 a) As discussed in L-2-1 page 4, the "Efficiency" aspect of rate design principle is about  
16 encouraging customers to maximize use of existing distribution assets and encourage existing  
17 and new customers to use the system in ways that lead to rational growth. "Efficiency" was  
18 generally considered with respect to "all-in" distribution rates, including commodity costs.

19

20 The OEB has been taking the lead with respect to distribution rate design, initiating policy  
21 proceedings such as "Residential Move to All Fixed Distribution Rates" and "C & I Rate Design"  
22 (e.g. all-fixed distribution rates for small GS customers, Gross Load Billing/stand-by charges  
23 policies). Hydro One's proposals align with the OEB's established policies.

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Witness: LI Clement



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 122**

2  
3 **Reference:**

4 Exhibit L-2-1, Attachment 1, Pages 5-6  
5 EB-2020-0246, Exhibit I-5-7  
6

7 **Interrogatory:**

- 8 a) Is the approach used to determine the rates revenue requirement by class for the years 2024-  
9 2027 the same as that used in the 2018-2022 CIR?  
10  
11 b) In EB-2020-0246, VECC #7 questioned the bill impacts calculated due to the elimination of the  
12 Seasonal class and, as part of the response, Hydro One Distribution stated:

13  
14 *“The inconsistency is due to the methodology approved in Hydro*  
15 *One’s last distribution rates application (EB-2017-0049) for*  
16 *adjusting the annual revenue requirement by rate class over the*  
17 *2019 to 2022 period, and revenue-to-cost ratio adjustments in*  
18 *2019 and 2020.”*  
19

20 Does the approach used in the current Application resolve this inconsistency?

- 21 i. If yes, please explain how.  
22 ii. If no, please explain the potential impacts of this inconsistency on the derivation of  
23 distribution rates over the 2024-2027 period.  
24

25 **Response:**

- 26 a) No, the approach used to determine the rates revenue requirement by class for the years  
27 2024-2027 differs slightly from that used in 2018-2022 CIR. This slight change has addressed  
28 the concerns regarding the treatment of miscellaneous revenues that resulted in variations in  
29 rate increases among rate classes.<sup>1</sup> A detailed description of the approach used in this  
30 Application is provided in L-2-1 pages 5-6.  
31  
32 b) Yes, Hydro One believes that the approach used in the current application resolves the  
33 inconsistency referenced in this interrogatory.  
34 i. Table below shows how under the current approach the increase in rates revenue is  
35 consistent across all rate classes, while the approach used in 2018-2022 CIR would  
36 have resulted in higher increase for the Sentinel Light class.

---

<sup>1</sup> EB-2017-0049 OEB Decision and Order, issued March 7, 2019, pages 135 to 137

Rate Class	Revenue with 2023 Rates Revenue and 2024 Charge Determinants	2024 Rates Revenue by Rate Class_2018-2022 CIR Approach (before R/C Ratio Adjustments)	% change from 2023 to 2024_2018-2022 CIR Approach	2024 Rates Revenue by Rate Class_Current Approach (before R/C Ratio Adjustments)	% change from 2023 to 2024_Current Approach
UR	\$107,377,343	\$112,223,617	4.5%	\$112,158,519	4.5%
R1	\$404,562,442	\$422,619,281	4.5%	\$422,576,337	4.5%
R2	\$622,276,981	\$649,889,794	4.4%	\$649,985,022	4.5%
GSe	\$162,460,211	\$169,655,860	4.4%	\$169,694,054	4.5%
GSd	\$135,606,943	\$141,572,683	4.4%	\$141,645,095	4.5%
UGe	\$22,516,800	\$23,518,145	4.4%	\$23,519,402	4.5%
UGd	\$26,421,062	\$27,584,524	4.4%	\$27,597,509	4.5%
St Lgt	\$9,102,390	\$9,507,734	4.5%	\$9,507,690	4.5%
Sen Lgt	\$2,382,942	\$2,604,948	9.3%	\$2,489,047	4.5%
USL	\$3,129,187	\$3,268,616	4.5%	\$3,268,520	4.5%
DGen	\$5,812,913	\$6,067,976	4.4%	\$6,071,743	4.5%
ST	\$60,546,917	\$63,224,709	4.4%	\$63,242,881	4.5%
AUR	\$5,521,429	\$5,772,277	4.5%	\$5,767,281	4.5%
AUGe	\$1,031,313	\$1,077,471	4.5%	\$1,077,234	4.5%
AUGd	\$1,152,377	\$1,204,096	4.5%	\$1,203,689	4.5%
AR	\$16,905,256	\$17,669,849	4.5%	\$17,657,994	4.5%
AGSe	\$3,896,243	\$4,070,069	4.5%	\$4,069,731	4.5%
AGSd	\$3,164,729	\$3,305,743	4.5%	\$3,305,644	4.5%

1  
 2

ii. Not Applicable

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 123**

2  
3 **Reference:**

4 Exhibit L-2-1, Attachment 1, Pages 5-9

5  
6 **Preamble:**

7 The description of the determination of the rates revenue requirement by class for the years  
8 2024-2027 on pages 5-6 simply makes reference to the subsequent steps undertaken in  
9 Attachment 1 to: i) also allocate the total costs to customer classes, ii) to calculated revenue to  
10 cost ratios and iii) adjust the rate revenue requirement by class as required to maintain the OEB's  
11 revenue to cost policy ranges.

12  
13 **Interrogatory:**

14 a) Please confirm that the billing determinants for the various rate classes (i.e.,  
15 customer/connection counts, kWh values and kW values) do not all change by the same  
16 percentage for each year during the 2024-2027 period. If not confirmed, why not.

17  
18 b) If confirmed, would it be reasonable to conclude that the cost allocation parameters (e.g.,  
19 customer/connection count, 12 CP values and 4NCP values) for each customer class will not  
20 all change by the same percentage for each year during the 2024-2027 period?

21 i. If yes, why in Attachment 1 is it reasonable to assume that the costs allocated to each  
22 rate class (Column D) will increase by the same amount for each year in the 2024-  
23 2027 period?

24  
25 c) Would it not be simpler and just as accurate to, for each of the years 2024-2027, increase the  
26 rates for all customer classes by the same percentage (i.e., the percentage calculated in Step  
27 4 on page 5 of Exhibit L, Tab 2, Schedule 1)?

28  
29 **Response:**

30 a) Confirmed.

31  
32 b) Yes, the cost allocation parameters referenced in the interrogatory will not change by the  
33 same percentage for all rate classes during the 2024-2027 period. However, it is not Hydro  
34 One's proposal to update the cost allocation model in the 2024-2027 period. This approach  
35 is consistent with the Renewed Regulatory Framework's objective of using a mechanistic  
36 approach for setting rates over the Custom IR period.

Witness: LI Clement

- 1           i.    It is unclear as to how, without running the CAM for each year, the allocated costs for  
2               each class could be adjusted to take into account the load forecast by rate class.  
3               However, it should be noted that changing the costs allocated to the rate classes  
4               would not impact rates unless the revenue-to-cost ratio of the affected rate class  
5               departs from the OEB approved range.  
6
- 7    c)   No, it would not be as accurate to increase the rates for all customer classes by the same  
8       percentage for each of the years 2024-2027. With Hydro One's proposed methodology,  
9       after step 4 (L-2-1 page 5), the 2024 rates revenue requirement by rate class is divided by  
10       the 2024 charge determinants by rate class to determine the rates. This additional step  
11       incorporates the impact of year-over-year changes in charge determinants by rate class into  
12       the 2024 rates, resulting in more accurate cost recovery by rate class, which is consistent  
13       with the rate setting.

1     **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 124**

2

3     **Reference:**

4     Exhibit L-2-1, Pages 9-10

5     Exhibit L-2-1, Attachment 2, Pages 3-4

6

7     **Interrogatory:**

8     a) It is noted that, for the R2 class, the increase in the monthly fixed charge due to the move to  
9       a fully fixed rate is \$7.92 in 2023 and \$8.24 in 2024. Are these increases comparable to the  
10      increases that were anticipated when the Board approved the phase-in period for the R2  
11      class?

12

13     **Response:**

14     Yes, these increases are comparable to the increases that were anticipated when the Board  
15     approved the phase-in period for the R2 class.

16

17     In its Submissions on DRO EB-2015-0079, filed on December 10, 2015, page 6, OEB staff showed  
18     that the annual fixed rate increase for low volume R2 customers was estimated to be \$8.38 with  
19     a 7-year transition period. In its Decision and Order on EB-2015-0079, issued on December 22,  
20     2015, the OEB acknowledged OEB staff's findings, approving an 8-year transition period for R2  
21     rate class.

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EB-2021-0110  
Exhibit I  
Tab 24  
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Page 2 of 2

1

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Witness: LI Clement

1     **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 125**

2

3     **Reference:**

4     Exhibit L-2-1, Pages 10-11 and 22

5     Exhibit L-1-3, Attachment 1, Tab O2

6     Exhibit L-7-2, Attachment 1

7

8     **Interrogatory:**

9     a) Please provide a schedule that for each rate class sets out: i) the 2022 approved fixed monthly  
10         charge, ii) the proposed 2023 fixed monthly charge and iii) the value for the Customer Unit  
11         Cost per month - Minimum System with PLCC Adjustment per Tab O2 of the 2023 CAM.

12

13     b) The Application states (page 22): “For the Streetlight, Sentinel light and Unmetered Scattered  
14         Load classes, customers will continue to be charged a monthly per account service.” If for  
15         either of the USL, Sentinel Light or Street Light classes, the fixed charge billing determinant is  
16         not the same as the determinant used to calculate the Customer Unit Cost per month -  
17         Minimum System with PLCC Adjustment value for the class, please re-calculate the Customer  
18         Unit Cost per month - Minimum System with PLCC Adjustment value per Tab O2 using the  
19         actual billing determinant for the class.

1 **Response:**

2 a) Table below provides the requested information.

3

Rate Class	2022 Fixed Charge (Estimated)	2023 Proposed Fixed Charge	2023 Customer Unit Cost per Month - Minimum System with PLCC Adjustment
UR	\$37.66	\$35.88	\$22.08
R1	\$55.52	\$57.22	\$29.28
R2	\$127.30	\$116.58	\$53.40
GSe	\$33.80	\$30.95	\$20.41
GSd	\$112.58	\$99.80	\$53.51
UGe	\$26.69	\$24.10	\$13.03
UGd	\$103.78	\$91.19	\$51.19
USL	\$39.42	\$34.68	\$35.15
Street Light	\$3.67	\$2.97	\$15.09
Sentinel Light	\$3.14	\$2.83	\$16.04
DGen	\$202.25	\$192.51	\$142.22
ST-Service Charge	\$607.11	\$771.22	\$53.93
ST-Meter Charge	\$762.69	\$391.31	
AUR	\$31.08	\$29.59	\$21.31
AUGe	\$26.08	\$25.36	\$7.04
AUGd	\$144.90	\$150.84	\$32.26
AR	\$37.75	\$35.94	\$23.72
AGSe	\$39.54	\$37.65	\$5.06
AGSd	\$168.45	\$171.20	\$52.94

4

5 b) The recalculated value of the Customer Unit Cost per month (Minimum System with PLCC  
 6 Adjustment) for the Street Light class is \$56.75/month and for the Sentinel Light class is  
 7 \$8.02/month.



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 126**

2  
3 **Reference:**

4 Exhibit L-2-1, Pages 14 and 18-21

5 Exhibit L-1-3, Attachment 1

6  
7 **Preamble:**

8 The Application states (page 14):

9  
10 *“Under this proposal, while ST customers will continue to be fully*  
11 *responsible for the costs of the local transformation, they will be*  
12 *offered an option to connect to Hydro One owned local*  
13 *transformation. Customers who choose this new option will be*  
14 *subject to a fixed monthly “local transformation charge” and a*  
15 *one-time transformation capital contribution. The derivation of*  
16 *this new charge does not affect the methodology used to*  
17 *establish the existing ST rates.”*

18  
19 **Interrogatory:**

20 a) With respect to the 2023 CAM, in what USOA (asset) account are the costs of the Hydro One  
21 owned local transformation included?

22  
23 b) How are the costs in the USOA account identified in part (a) allocated to the rate classes? As  
24 part of the response, please provide the percentage of the costs that will be allocated to each  
25 rate class.

26  
27 c) Have any changes been made to the 2023 CAM methodology or inputs to reflect the option  
28 ST customers will have under the proposal outlined in the preamble.

29 i. If yes, please outline what changes have been made and why.

30  
31 **Response:**

32 a) Hydro One owned local transformation costs are included in USofA 1850 (Line Transformers).

33  
34 b) 62% of the costs in USofA 1850 are allocated using the Line Transformer Customer Base -  
35 excluding ST customers (“CCLT”), adjusted for customer density. The remaining 38% of the  
36 costs are allocated using Line Transformer NCP4-excluding ST (“LTNCP4”), adjusted for  
37 customer density. The allocation is also affected by the proposed direct allocation factors for

Witness: LI Clement

1 the new acquired rate classes as shown in Tab "E2 Allocators" of the 2023 CAM (rows 437-  
2 507). Table below provides the final allocation of Line Transformation costs to each rate class.

3

UR	R1	R2	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	AUR	AUGe	AUGd	AR	AGSe	AGSd
4.1%	17.1%	32.9%	12.8%	23.3%	2.2%	4.0%	0.7%	0.4%	0.3%	0.0%	0.0%	0.2%	0.1%	0.1%	0.9%	0.4%	0.4%

4

5

6 c) No changes have been made to the 2023 CAM methodology or inputs to reflect the option ST  
7 customers will have under the proposal outlined in the preamble.

8

i. Not applicable.

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 127**

2  
3 **Reference:**

4 Exhibit L-2-1, Pages 19-20  
5 Exhibit L-1-3, Attachment 1  
6

7 **Preamble:**

8 The Application states:

9  
10 *"In addition to the installed capital costs described above, the*  
11 *calculation of the transformation charge also includes the costs*  
12 *associated with keeping spare transformers for ST customers, the*  
13 *costs associated with replacing failed transformers, and the cost*  
14 *associated with the on-going visual inspection of these ST*  
15 *transformers."*  
16

17 **Interrogatory:**

- 18 a) Please provide the supporting details/calculations for the annual costs set out in Table 11.  
19  
20 b) What types of overheads were included in the annual costs and did they include an allowance  
21 for corporate overheads or general plant?  
22  
23 c) In calculating the transformation charge was any provision made for ongoing maintenance  
24 and repair costs over and above the costs of on-going visual inspection?  
25

26 **Response:**

- 27 a) A breakdown of annual costs is provided below:  
28  
29

**Table 1 - Estimated Annual Costs including Overheads (in 1,000s)**

Description	Type of Cash Flow	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Equipment Connection	Capital Expenditure	486	128	130	144	135	138	152	143	146	162
Spares	Capital Expenditure	178	202	-	-	-	13	-	-	-	5
Failures	Capital Expenditure	22	28	34	41	47	54	61	68	75	84
OMA cost	OM&A Costs	0	0	0	0	0	0	0	0	1	1

30  
31 In addition to the above annual costs, approximately \$350,000 of capital cost was included  
32 in the calculation to capture the NBV of existing in-service Hydro One service transformers  
33 that will supply customers that are moved to the ST rate class.

Witness: LI Clement

1           Emergency spare inventory costs are higher in 2023 and 2024 as new emergency spare units  
2           are purchased to support the larger transformers being offered.

3

4           A 1.25% annual failure rate was assumed in calculating the annual cost of replacing failed  
5           transformers.

6

7           b) Annual expenditures include the standard corporate overhead allocation.

8

9           c) No, only visual inspection costs were included in the annual OM&A calculations. Service  
10          transformers are replaced on failure.

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 128**

2

3 **Reference:**

4 Exhibit L-2-1, Page 20

5 Exhibit L-1-3, Attachment 1

6

7 **Preamble:**

8 The Application states:

9

10 *“For the purposes of cost allocation, the revenue from this new*  
11 *charge will be recorded as a revenue off-set in USofA Account*  
12 *4220 – “Other Electric Revenue”. This revenue off-set has been*  
13 *allocated to all non-ST rates classes in the 2023 CAM to ensure*  
14 *that the incremental costs of supplying local transformation to ST*  
15 *customers are not borne by non-ST customers.”*

16

17 **Interrogatory:**

18 a) With reference to the 2023 CAM, please indicate where in the model these revenues are  
19 included (e.g., what USOA account in Tab I3) and where in Tab E2 the allocation details are  
20 documented.

21

22 b) Is the allocation factor used for the revenues the same factor as it used to allocate the costs  
23 associated with Hydro One Distribution owned local transformation?

24

25 **Response:**

26 a) For cost allocation purposes, the revenues from the new local transformation charge for the  
27 ST class has been included in USofA 4220 - “Other Electric Revenue” in Tab I3 of the 2023  
28 CAM. As shown in Tab E4 of the CAM (TB Allocation Details), allocator used for this USofA is  
29 1850 and the allocation details can be found in row 137 of Tab E2.

30

31 b) As mentioned in response to part a), revenues from the new charge have been allocated using  
32 Hydro One owned local transformation assets (as recorded in USofA 1850).

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1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 129**

2

3 **Reference:**

4 Exhibit L-2-1, Page 16

5

6 **Preamble:**

7 The Application states:

8 *"The Common ST Line rate will be adjusted to reflect changes to*  
 9 *the HVDS-high charge, as a part of Hydro One's expected annual*  
 10 *applications from 2024 for 2027."*

11

12 **Interrogatory:**

13 a) Please describe how Common ST Line rate will be adjusted to reflect changes in the HVDS-  
 14 high charge and provide an illustrative example.

15

16 **Response:**

17 a) As described in Exhibit L, Tab 2, Schedule 1, Section 5.2.2, the amount that is not recovered  
 18 through the other ST charges, including HVDS High, is recovered through the Common ST Line  
 19 charge. An example of an adjustment to the ST common line charge resulting from an  
 20 illustrative 3% increase in HVDS charges is provided below:

21

	Proposed 2023 (L-02-01-04)		VECC-029 2023 Illustration	
<u>Minus</u>	Revenue Generated (Annual)	Input	Illustrative Example Adjustment	Revenue Generated (Annual)
HVDS-high cost allocation	\$ 3,023,599	(A)	Increase Revenue 3%	\$ 3,114,307
HVDS-low cost allocation	\$ 297,376	(B)	Increase Revenue 3%	\$ 306,297
LVDS-low cost allocation	\$ 1,246,104	(C)	N/A	\$ 1,306,218
Specific ST lines	\$ 344,899	(D)	N/A	\$ 361,544
<u>Plus:</u>	\$ -			\$ -
Service Charge (per Delivery Point)	\$ 8,421,722	(E)	N/A	\$ 8,837,092
Meter Charge (for Hydro One ownership per Meter Point)	\$ 2,854,998	(F)	N/A	\$ 2,995,755
Total revenue generated through other delivery charges:	\$ 16,188,698	(G = A+B+C+D+E+F)		\$ 16,921,214
Revenue to be recovered through ST rates	\$ 60,270,407	(H=L-02-01-01 (K+L))		\$ 60,270,407
ST Common Line Revenue Requirement (Annual \$)	\$ 44,081,709	(I=H-G)		\$ 43,349,194
ST Common Line Charge Determinant (Annual kW)		(J)		
<b>ST Common Line Charge (Monthly \$/kW)</b>	<b>\$ 1.4638</b>	<b>(K=I/J)</b>		<b>\$ 1.4394</b>

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Exhibit I  
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Witness: LI Clement



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 130**

2  
3 **Reference:**

4 Exhibit L-2-1, Pages 17-18

5  
6 **Preamble:**

7 The Application states:

- 8 • *“Customers in the ST class can obtain transformation from above 50 kV to a voltage*  
9 *between 44 kV and 13.8 kV either through the use of a High Voltage Distribution Station,*  
10 *referred to as an “HVDS-high” station, or a TS owned by Hydro One Transmission.” (page*  
11 *17)*
- 12 • *“for consistency purposes, the HVDS-high rate is set equivalent to the RTSR –*  
13 *Transformation rate adjusted for losses. HVDS-high is a volumetric charge.” (page 17)*
- 14 • *“High Voltage Distribution Station that transforms power from above 50 kV to under 13.8*  
15 *kV, is referred to as an “HVDS-low” station”. (page 18)*
- 16 • *“the HVDS-low rate is set to be the sum of the HVDS-high rate and LVDS-low rate.” (page*  
17 *18)*
- 18 • *“Low Voltage Distribution Station, referred to as an “LVDS-low” station, transforms power*  
19 *from above (or at) 13.8 kV to under 13.8 kV.” (page 18)*
- 20 • *“The ST LVDS low portion of the distribution stations costs is based on the gross book value*  
21 *of assets associated with providing ST service from LVDS-low stations as a share of the*  
22 *total LVDS station assets. LVDS-low is a volumetric charge.” (page 18)*

23  
24 **Interrogatory:**

- 25 a) Overall, do the rates charged for HVDS-high and HVDS-low over or under recover the cost of  
26 HVDS stations allocated to the ST class and by how much?

27  
28 **Response:**

- 29 a) The revenue received from the proposed 2023 HVDS-high and HVDS-low rates is estimated at  
30 \$3.3M (proposed rates x 2023 charge determinants). The cost of HVDS stations allocated to  
31 the ST class in the cost allocation model is estimated at \$4.6M. Based on these estimations,  
32 the proposed rates under recover the cost by about \$1.3M, which is largely consistent with  
33 the fact that the ST class rates on average under-collect costs at a revenue to cost ratio of  
34 0.86.

1       As described in Exhibit L, Tab 2, Schedule 1, Section 5.2.3, the ST HVDS charges are set equal  
2       to the ST RTSR transformation charge. This ensures that charges for transformation from  
3       above 50 kV to a voltage between 44 kV and 13.8 kV are consistent for customers that are  
4       supplied from an HVDS or TS owned by Hydro One Transmission.

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 131**

2  
3 **Reference:**

4 Exhibit L-2-1, Pages 23-35

5  
6 **Preamble:**

7 The Application states (pages 23-24): *“The total IESO transmission charges are allocated to each*  
8 *of the distribution rate classes in proportion to their coincident demand to Hydro One’s network*  
9 *and connection peaks at the transmission delivery points.”*

10  
11 It also states: *“The use of Hydro One’s RTSR methodology is important to ensure that ST*  
12 *customers, which include all embedded LDCs supplying their own customers’ load, pay an*  
13 *appropriate share of transmission charges levied to Hydro One.”*

14  
15 **Interrogatory:**

- 16 a) Please clarify specifically what demand from each delivery point is used to allocate: i) network  
17 costs and ii) line connection and transformation connection costs.
- 18
- 19 b) Why is the use of Hydro One’s RTSR methodology (as opposed to the RTSR Workform) is  
20 important to ensure that ST customers, which include all embedded LDCs supplying their own  
21 customers’ load, pay an appropriate share of transmission charges levied to Hydro One?
- 22
- 23 c) Is Hydro One Distribution charged RTSRs by other LDCs where Hydro One is an embedded  
24 utility (per A/2/3, page 6)?
- 25 i. If not, why not?
- 26 ii. If yes, how are these charges accounted for in the determination of the Retail  
27 Transmission Rates?

28  
29 **Response:**

- 30 a) With the exception of the ST rate class, the forecast 2023 demand for each rate class that is  
31 coincident with the forecast 2023 monthly transmission and distribution system peak is used  
32 to allocate the estimated Network and Connection transmission charges, respectively.

33  
34 For the ST rate class, the forecast 2023 demand for each ST customer that is coincident with  
35 the network, line connection and transformation connection billing peak demand of its  
36 supplying Transmission delivery point is used for the allocation of the corresponding charges.

- 1 b) The RTSR workform applies a methodology that is based on historical allocation information  
2 to determine the proposed RTSRs. Hydro One’s RTSR methodology leverages the available  
3 hourly Transmission and ST delivery point forecasts, as well as the hourly distribution rate  
4 class actual and forecast load shapes. These are used to estimate the forecast transmission  
5 charges as well as the coincident distribution demand for the test year by rate class. Using  
6 this hourly information is important as it captures the latest trends and changes among the  
7 rate classes, resulting in appropriate allocation of forecast transmission charges among the  
8 rate classes.  
9
- 10 c)
- 11 i. Yes, Hydro One Distribution is charged RTSRs by other LDCs where Hydro One is an  
12 embedded utility.  
13
- 14 ii. These charges are not accounted for in the determination of the Retail Transmission  
15 Rates, rather, as has been previously approved by the OEB, these charges are  
16 captured in the RSVA – Retail Transmission Network and Connection Accounts (1584  
17 and 1586). Hydro One customers pay for these costs when the RSVA accounts are  
18 disposed of.

1     **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 132**

2

3     **Reference:**

4     Exhibit A-2-3, Page 6

5

6     **Preamble:**

7     The Application indicates that Hydro One Distribution is partially embedded in a number of other  
8     Ontario electricity distributors.

9

10    **Interrogatory:**

11    a) Given Hydro One Distribution is partially embedded in a number of other Ontario electricity  
12       distributors, why does Hydro One Distribution not have any LV rates to recover the  
13       distribution charges from these utilities? How are any such charges recovered?

14

15    **Response:**

16    Hydro One Distribution is charged distribution charges by other LDCs where Hydro One is an  
17    embedded utility. These charges are captured as “costs” in the RSVA – LV Account (1550). Hydro  
18    One customers will pay for these costs when this RSVA account is disposed of.

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Witness: LI Clement

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 133**

2  
3 **Reference:**

4 Exhibit L-3-1, Pages 9-13 and Attachment 3  
5 Exhibit L-1-3, Attachment 1  
6

7 **Interrogatory:**

- 8 a) With respect to Attachment 3, Tab 1, are the in-service additions for each year net of  
9 retirements? If not, how is retirement of assets over the 2016-2022 period accounted for?  
10
- 11 b) With respect to Attachment 3, Tab 2, it is noted that for Woodstock's USOA 1815 the class  
12 allocation factors for Norfolk+Haldimand were used. What would be the class allocation if  
13 based on the appropriate allocators from Woodstock's last CAM model?  
14
- 15 c) With respect to Attachment 3, Tab 5 (lines 20-52) please address the following:
- 16 i. With reference to the various columns please explain how the "bulk assets" attributable  
17 to the acquired utilities are calculated. (i.e., how does multiplying the values of the assets  
18 specifically related to the acquired utilities (per Tab 3) by the factors derived in Column F  
19 and G yield the appropriate proportion of Hydro One Distribution's bulk assets that should  
20 be assigned to the acquired utilities?).
- 21 ii. Please explain what the "Bulk Factor" (Column F) is meant to represent and why the  
22 formula used yields the desired result. As an illustration, please explain the derivation of  
23 the factor for USOA 1830.
- 24 iii. Please explain what Column G is meant to represent and why the formula used yields the  
25 desired result.  
26

27 **Response:**

- 28 a) No, in-service additions are not net of retirements. Please refer to interrogatory response at  
29 L-Staff-327 (c) for further details.  
30
- 31 b) Woodstock's last Cost Allocation Model (EB-2010-0145) did not have any amount in USofA  
32 1815. This was the reason Hydro One used Norfolk + Haldimand allocation factors as an  
33 approximation.  
34
- 35 c)
- 36 i. Before acquisition, former Norfolk Power and Haldimand County Hydro were partially  
37 embedded in Hydro One Distribution's service territory and were billed as Hydro One

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1 Distribution’s Sub-Transmission customers. Therefore, in addition to the forecast GBV  
 2 shown in Tab 3 of the referenced Attachment 3, the three acquired rate classes with  
 3 Norfolk and Haldimand customers (namely AR, AGSe and AGSd) should also be  
 4 allocated a portion of the total “bulk assets” used to serve them. This is achieved using  
 5 the factors in Columns F and G, as explained in parts ii and iii below.  
 6

7 ii. The factor in Column F represents the amount of “bulk assets” as a percentage of the  
 8 total Primary and Secondary assets required to serve all Hydro One customer classes.  
 9 In order to treat the acquired classes in a consistent manner as all other Hydro One  
 10 classes that make use of bulk assets, the forecast Primary and Secondary GBV in Tab  
 11 3 of Attachment 3 is multiplied by this same percentage in order to estimate the  
 12 amount of bulk assets used by the acquired AR, AGSe and AGSd classes, assuming the  
 13 entire load of former Norfolk Power and Haldimand County Hydro was served by  
 14 Hydro One Distribution.  
 15

16 iii. The factor in Column G is meant to account for the fact that these acquired utilities  
 17 were only partially embedded in Hydro One Distribution service territory, and  
 18 therefore not all of their load was provided through the bulk system. The table below  
 19 provides the derivation of “bulk assets” to be added to the forecast 2023 GBV from  
 20 Tab 3 in Attachment 3 using USofA 1830 and rate class AR as an illustrative example.  
 21

USofA	Description	Asset Values
1830-3B	Bulk-Retail Poles, Tower & Fixtures (A)	\$1,766,025,252
1830-4B	Primary-Retail Poles, Tower & Fixtures (B)	\$1,681,285,492
1830-5	Secondary-Poles, Tower & Fixtures (C)	\$1,247,701,811
1830	"Bulk assets" as percentage of Primary and Secondary assets ( $D=A/(B+C)$ )	60.3%
	Total Primary and Secondary assets allocated to AR class per Tab 3 of Attachment 3 (E)	\$41,574,834
	Estimate of “Bulk assets” that should be allocated to AR class ( $F = D \times E$ )	\$25,067,438
	Estimated total demand of former Norfolk Power and Haldimand County Hydro served by Hydro One DX based on Network demand from their last-filed RTSR work form, as shown in Tab 5a of Attachment 3) (G)	28.2%
	Additional "bulk assets" that should be allocated to AR class ( $H=F*G$ )	\$7,059,713
	Total assets allocated to AR class ( $I=E+H$ )	\$48,634,548



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 134**

2  
3 **Reference:**

4 Exhibit L-3-1, Pages 9-13, and Attachment 3  
5 Exhibit L-1-3, Attachment 1  
6

7 **Interrogatory:**

- 8 a) Please explain where/how the GFA, NFA and Depreciation Direct Allocation Factors are  
9 incorporated into the 2023 CAM for purposes of allocating cost to the six acquired utility rate  
10 classes.  
11
- 12 b) Are the costs in accounts 1815 to 1860 all allocated to customer classes on the same basis?  
13 If not, what are the differences in how the costs in the accounts are allocated?  
14
- 15 c) Please provide a schedule that set outs out for each of the accounts 1815 to 1860 the GBV  
16 allocated to each of the six acquired utility customer classes per the 2023 CAM.  
17
- 18 d) It is noted that the GFA Direct Allocation Factors are calculated based on the aggregate value  
19 of the USOA 1815-1860 assets for each customer class. Please provide a schedule that sets  
20 out the resulting GFA Direct Allocation Factors by rate class for each USOA – where the values  
21 are calculated separately for each USOA.  
22
- 23 e) The Application states that “The amount of GFA not assigned to the new acquired rate classes  
24 as a result of applying the direct allocation factors shown above is subsequently redistributed  
25 to all other rate classes in proportion to the amounts already assigned to those classes.”  
26 Please explain where/how this is done in the 2023 CAM.  
27

28 **Response:**

- 29 a) The GFA direct allocation factors are incorporated in the CAM Tab “E2 Allocators” at rows  
30 437-507 where the GFA assigned to the new acquired rate classes is reduced by the direct  
31 allocation factors and the difference is re-allocated to Hydro One legacy rate classes.  
32 Similarly, the NFA direct allocation factors are incorporated in the CAM Tab “E2 Allocators” at  
33 rows 509-525.  
34

35 The Depreciation direct allocation factors are incorporated in the CAM Tab “O4 Summary by  
36 Class and Accounts” at rows 276-286.

- 1 b) No, costs in accounts 1815 to 1860 are not all allocated to customer classes on the same basis.  
 2 The basis for the allocation of these USofA accounts is specified in Tab E4 of the CAM. As an  
 3 example, the demand-related costs (e.g., USofA 1815-Transformer Station Equipment) are  
 4 allocated to customer classes using CP/NCP values, customer related costs (e.g., USofA 1860-  
 5 Meters) are allocated using number of customers/meter capital costs and joint (demand and  
 6 customer related) costs (e.g., USofA 1830-Pole, Towers and Fixtures) are allocated using  
 7 combination of CP/NCP and number of customers.  
 8  
 9 c) The requested information can be found in cells U8:Z16 in Tab "5. Determine Alloc for Acq"  
 10 of Exhibit L-01-03-03. It has been reproduced in the table below for ease of reference.  
 11

USofA	AUR	AUGe	AUGd	AR	AGSe	AGSd
1815	\$ 1,416,875	\$ 379,647	\$ 1,018,397	\$ 3,991,982	\$ 1,108,852	\$ 1,807,275
1820	\$ 5,207,998	\$ 2,711,198	\$ 8,028,171	\$ 14,624,123	\$ 7,317,830	\$ 15,445,881
1830	\$ 38,247,010	\$ 10,345,364	\$ 17,319,132	\$ 103,067,576	\$ 29,095,231	\$ 31,908,057
1835	\$ 19,338,197	\$ 4,880,307	\$ 10,477,617	\$ 51,724,898	\$ 13,756,797	\$ 19,514,086
1840	\$ 280,045	\$ 68,648	\$ 160,957	\$ 740,852	\$ 192,334	\$ 304,023
1845	\$ 4,417,738	\$ 1,082,928	\$ 2,539,121	\$ 11,687,023	\$ 3,034,088	\$ 4,796,001
1850	\$ 18,472,330	\$ 9,250,971	\$ 16,643,318	\$ 46,539,429	\$ 23,782,635	\$ 39,352,701
1855	\$ 5,532,892	\$ -	\$ -	\$ 20,909,460	\$ -	\$ -
1860	\$ 7,090,725	\$ 1,558,869	\$ 424,715	\$ 13,694,688	\$ 3,032,653	\$ 878,775

- 12  
 13 d) The table below provides the requested information.  
 14

USofA	AUR	AUGe	AUGd	AR	AGSe	AGSd
1815	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1820	5.3%	5.7%	3.2%	16.9%	17.9%	13.2%
1830	24.8%	17.5%	14.3%	47.2%	39.8%	38.6%
1835	31.8%	17.0%	10.8%	52.9%	46.9%	34.7%
1840	1260.6%	597.7%	348.4%	627.5%	608.0%	412.6%
1845	150.0%	71.1%	41.4%	107.1%	95.2%	60.8%
1850	40.2%	24.5%	14.6%	68.3%	31.9%	17.5%
1855	0.0%			23.7%		
1860	38.4%	236.6%	452.3%	93.5%	100.8%	141.4%

- 15  
 16 e) Please refer to response in part (a).

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 135**

2

3 **Reference:**

4 Exhibit L-3-1, Pages 9-13, and Attachment 3

5

6 **Interrogatory:**

7 a) Does Hydro One Distribution intend to continue to track the capital additions for the acquired  
8 utilities?

9

10 b) Please outline how Hydro One Distribution intends to calculate the GFA Direct Allocation  
11 Factors for purposes is next rebasing/CIR application.

12

13 **Response:**

14 a) Yes, Hydro One will track capital additions for the Acquired Utilities for as long as the Board  
15 advises that information is required to set rates in future rate proceedings.

16

17 b) Hydro One plans to use the same methodology proposed in this Application, as described in  
18 L-1-3 section 2.2.7.2.

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1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 136**

2  
3 **Reference:**

4 Exhibit L-3-1, Pages 3-7

5 Exhibit L-3-1, Attachments 1, 2 and 3

6  
7 **Interrogatory:**

8 a) With respect to Attachment 2, for each of the three acquired utilities please explain how the  
9 following values were derived for the end of the deferral period:

10 i. Depreciation

11 ii. Cost of Debt

12 iii. Cost of Equity

13 iv. Tax

14 v. Revenue Offsets

15  
16 b) With respect to Attachment 3, what would be the resulting CAGR based on: i) the average  
17 value of all the individual CAGR's used in the Attachment and ii) the median values of all the  
18 individual CAGR's used in the Attachment?

19  
20 c) With respect to Table 3 (L/3/1), please provide a table with separate values for Norfolk and  
21 Haldimand.

22  
23 **Response:**

24 a) The calculation of the Status Quo revenue requirement in Exhibit L-3-1, Attachment 1, for the  
25 three Acquired Utilities, uses the following assumptions.

26  
27 i. Depreciation - Annual depreciation for each LDC is calculated using the average 2013 and  
28 2014<sup>[2]</sup> depreciation rates for each acquired LDC prior to acquisition given that prior to  
29 2013 each LDC is assumed to have been using CGAAP depreciation methodology and had  
30 not adopted the OEB-mandated MIFRS depreciation rates. This rate is then applied to the  
31 LDC's 2013 and 2014 average gross fixed assets, per the OEB's Annual Yearbook, to  
32 calculate an average depreciation amount for that specific LDC.

33 o That average rate is then applied annually in each of the five rate base deferral  
34 years to the gross assets, as forecast for the 5-year period.

35  
36 ii. The debt rates, both long and short term, are assumed to be the OEB-issued<sup>[5]</sup> rates in  
37 effect for each year of the deferral period.

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- 1           iii. The ROE rate is assumed to be the OEB-issued ROE<sup>[6]</sup> rate in effect for each year of the  
2           deferral period.  
3
- 4           iv. The tax rate used is the combined federal and provincial tax rate of 26.5%, with an  
5           effective tax rate of 15.90%.  
6
- 7           v. Revenue Offsets – This value is sourced from each of the last OEB-approved rebasing  
8           applications. Woodstock EB-2010-0145 – Draft Rate Order<sup>1</sup>; Norfolk (EB-2011-0272)  
9           Norkfolk 2012 RRWF Proposed Tariff<sup>2</sup>; Haldimand - Revenue Requirement Settlement  
10          Form (EB-2013-0134)<sup>3</sup>. The Revenue Offset Amount is kept constant over the forecast  
11          period.  
12
- 13       b)
- 14          i. Hydro One’s calculation of the status quo revenue requirement excluded the CAGR for  
15          those utilities whose revenue requirement was impacted by the savings achieved through  
16          consolidation activities given that the purpose of the analysis is to simulate what a utility’s  
17          revenue requirement likely would have been, and what the OEB might have approved, if  
18          the consolidation did not occur. To include the CAGR for utilities with synergy savings  
19          achieved through MAAD consolidations would distort this figure.  
20
- 21                However, for the purpose of responding to this interrogatory, Hydro One has performed  
22                the calculation including the utilities that were part of a MAADs approval in the table  
23                provided at Exhibit L-3-1, Attachment 3. The CAGR would be 2.8%. The upper goal post  
24                for Norfolk and Haldimand would be \$32,556,033 and for Woodstock \$9,211,818. This  
25                still results in Hydro One’s proposed revenue requirement to be collected from the  
26                acquired customer groups falling within the goalposts.  
27
- 28          ii. Hydro One, as noted in Footnote 2 of Exhibit L-3-1, believes that the more accurate way  
29          to estimate a utility’s status quo revenue requirement is to use the acquired utility’s own  
30          forecast, if available. Unfortunately for these three utilities that information was not  
31          attained nor thought to be needed, at the time the consolidation occurred.  
32

---

<sup>1</sup> File Source link - <https://www.rds.oeb.ca/CMWebDrawer/Record/267787/File/document> - On Tab “5. Rev\_Suff\_Def” cell P18.

<sup>2</sup>File Source link - <https://www.rds.oeb.ca/CMWebDrawer/Record/329435/File/document> - On Tab “8. Rev\_Suff\_Def” cell P18.

<sup>3</sup> File Source link - <https://www.rds.oeb.ca/CMWebDrawer/Record/432584/File/document> - On Tab “8. Rev\_Def\_Suff” cell P21.

1 The medium values for the individual CAGRs used in the table would be 2.47%.

2

3 The average CAGR approach was introduced by Board Staff in the Orillia and  
4 Peterborough MAADs and Hydro One believes it is a more accurate basis for forecasting  
5 a utility's future revenue requirement expectation when compared to the medium value  
6 approach, which by definition is just the middle number in a sorted list of data.

7

8 Using the medium value of 2.47%, the Upper Goal post for Norfolk and Haldimand would  
9 be \$32,103,602 and for Woodstock \$9,094,102. This still results in Hydro One's proposed  
10 revenue requirement to be collected from the acquired customer groups falling within  
11 the goalposts.

12

13 c)

	Norfolk	Haldimand	Woodstock	Total
2023 Estimated Revenue Requirement	\$15,227,384	\$16,761,460	\$9,294,535	\$41,283,379
2023 Estimated LV Charges	\$455,629	\$429,938	N/A	\$885,567
Total Estimated 2023 Cost to Serve	\$15,683,013	\$17,191,398	\$9,294,535	\$42,168,946

14

15 <sup>[1]</sup> OEB-issued Letter titled, *Allowance for Working Capital for Electricity Distribution Rate Applications*,  
16 dated June, 03, 2015.

17 <sup>[2]</sup> For Norfolk only 2013 was used, as this was the last year of the LDC being reported in the Yearbook prior  
18 to acquisition by Hydro One. Equivalent 2014 data did not exist for Norfolk.

19 <sup>[3]</sup> *Ibid*

20 <sup>[4]</sup> *Ibid*

21 <sup>[5]</sup> <https://www.oeb.ca/fr/node/2122>

22 <sup>[6]</sup> <https://www.oeb.ca/fr/node/2122>

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1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 137**

2

3 **Reference:**

4 Exhibit L-3-1, Pages 7-8

5

6 **Interrogatory:**

7 a) With respect to Table 4 (L/3/1), please provide a table with separate values for Norfolk and  
8 Haldimand.

9

10 **Response:**

11 a) The table below provides the requested information.

12

	<b>Norfolk</b>	<b>Haldimand</b>	<b>Woodstock</b>	<b>Total</b>
<b>Incremental Revenue Requirement</b>	\$9,824,960	\$13,147,197	\$7,014,125	\$29,986,281
<b>2023 Estimated LV Charges</b>	\$455,629	\$429,938	n/a	\$885,567
<b>Lower Goal Post</b>	\$10,280,589	\$13,577,135	\$7,014,125	\$30,871,849

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Witness: LI Clement

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 138**

2  
3 **Reference:**

4 Exhibit L-3-1, Pages 8-9

5  
6 **Interrogatory:**

7 a) Please provide a revised version of Table 5 (L/3/1) that separates out Norfolk and Haldimand.

8  
9 b) Please provide a revised version of Table 5 (L/3/1) where:

10 i. The Costs Allocated to the New Acquired Rate Classes is used instead of the Revenues  
11 Collected.

12 ii. If practical, for those acquired customers that will be moving to Hydro One's existing  
13 Street Light, Sentinel Light, Unmetered Scattered Load and Sub-Transmission rate classes,  
14 an appropriate portion of each class' allocated costs is used instead of an estimate of the  
15 revenue collected/costs charged.

16  
17 **Response:**

18 a) The table below provides the revised version of Table 5 (revenue collected from the acquired  
19 utility customers) with separate columns for Norfolk and Haldimand.

20

	Norfolk	Haldimand	Woodstock	Total
Revenues Collected from Customers in New Acquired Rate Classes	\$11,325,773	\$12,594,393	\$7,668,380	\$31,588,546
Revenues Collected from Acquired Customers moving to Hydro One's Legacy Rate Classes*	\$215,787	\$183,798	\$808,902	\$1,208,487
Total Revenues Collected from Acquired Customers	\$11,541,559	\$12,778,191	\$8,477,283	\$32,797,034

*\*Includes estimated rates revenue collected from the acquired customers that will be moving to Hydro One's existing Street Light, Sentinel Light, Unmetered Scattered Load and Sub-Transmission rate classes.*

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1 b) The table below provides the requested information in sub-parts i) and ii).

2

	<b>Norfolk and Haldimand</b>	<b>Woodstock</b>	<b>Total</b>
Costs Allocated to Customers in New Acquired Rate Classes*	\$28,205,205	\$8,582,946	\$36,788,151
Costs Allocated to Acquired Customers moving to Hydro One's Legacy Rate Classes*	\$397,476	\$883,756	\$1,281,232
<b>Total Costs Allocated to Acquired Customers</b>	<b>\$28,602,681</b>	<b>\$9,466,702</b>	<b>\$38,069,383</b>

\* Excludes Miscellaneous Revenues

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 139**

2

3 **Reference:**

4 Exhibit L-4-1, Page 2

5

6 **Interrogatory:**

7 a) Hydro One Distribution proposes to maintain SSCs at the 2022 OEB-approved amount for the  
8 2023 to 2027. With the exception of the charges set by the OEB for access to power poles  
9 (telecom), and Non-Payment of Account Services, why didn't Hydro One propose to escalate  
10 the other SCCs annually based on the OEB's approved inflation rate?

11

12 **Response:**

13 a) Hydro One didn't propose to escalate the other SCCs based on the OEB's approved inflation  
14 rate because SSCs were increased following EB-2017-0049 and as a result, Hydro One decided  
15 to maintain SSCs at their current level in this application.

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Witness: LI Clement

1     **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 140**

2

3     **Reference:**

4     Exhibit L-7-2, Attachment 1, Page 21

5

6     **Interrogatory:**

7     a) There is no mention in the Application has to how Hydro One Distribution proposes to set  
8         Retail Service Charges over the 2023-2027 period. Please address.

9

10    **Response:**

11    a) As required by the Report of the OEB on Energy Retailer Services Charges, issued on  
12         November 29, 2018 (EB-2015-0304), Retailer Service Charges will be adjusted for inflation  
13         every year over the 2023-2027 period.

Filed: 2021-11-29  
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Witness: LI Clement



1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 141**

2  
3 **Reference:**

4 Exhibit L-5-1, Page 6

5  
6 **Preamble:**

7 The Application states:

8  
9 *In its Decision in EB-2020-0194, the misallocated Future Tax Savings. Those riders*  
10 *will be in effect from July 1, 2021 to June 30, 2023. As a result of the assumption*  
11 *used in this application that the Seasonal class elimination will be implemented*  
12 *on January 1st, 2023, it is necessary to recalculate the amounts of the*  
13 *misallocated Future Tax Savings to be recovered from each rate class. This is*  
14 *accomplished by using the Net Fixed Assets allocator from the 2018 CAM under*  
15 *the 'No Seasonal' scenario as prepared in the Seasonal Class Elimination*  
16 *proceeding (EB-2020-0246). The Base Rate Adjustment Riders are then derived*  
17 *using the proposed 2023 charge determinants.*  
18

19 **Interrogatory:**

- 20 a) Please provide the calculations leading to the proposed charges set out in Table 4.  
21  
22 b) Please explain why the Net Fixed Assets allocator from the 2018 CAM under the 'No Seasonal'  
23 scenario is used to reallocate the amounts.  
24

25 **Response:**

- 26 a) Please refer to the evidence provided at Exhibit L, Tab 5, Schedule 1, Attachment 4 (MS Excel  
27 format).  
28  
29 b) The Base Rate Adjustment Rider currently in place (from July 1, 2021 to December 31, 2022)  
30 was calculated using Net Fixed Assets allocator from the OEB-approved 2018 CAM (EB-2017-  
31 0049). This approach was approved by the OEB in EB-2019-0194. Since the Seasonal rate class  
32 was assumed to have been eliminated in 2023, Hydro One used the Net Fixed Assets allocator  
33 from the 2018 "No Seasonal" CAM to be consistent with its previous approach.

Filed: 2021-11-29  
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Witness: LI Clement

1 **L - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 142**

2

3 **Reference:**

4 Exhibit L-6-1, Pages 18-19

5

6 **Interrogatory:**

7 a) The Application states that the bill credit will be calculated prior to January 1<sup>st</sup> of each year.  
8 In determining the bill credit for Sentinel Light and USL customers from acquired utilities, how  
9 will the bill for the upcoming year (prior to mitigation) be calculated? For example, will only  
10 the distribution related charges be changed from those applicable in the prior year or will  
11 some of the other charges (e.g., RTSRs) be changed to reflect known changes for the  
12 upcoming year?

13

14 **Response:**

15 a) The bill for the upcoming year (prior to mitigation) will be based on all known changes for the  
16 upcoming year:

17

18 • Average monthly consumption level during the previous 12 months;

19

20 • OEB approved distribution related rates for the upcoming year;

21

22 • OEB approved RTSR for the upcoming year; and

23

24 • Latest commodity prices, regulatory charges, subsidies, taxes.

Filed: 2021-11-29  
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