ONTARIO ENERGY BOARD
IN THE MATTER OF AN APPLICATION BY
HALTON HILLS HYDRO INC. ("HHHI")
2021 COST OF SERVICE APPLICATION
INTERROGATORY RESPONSES FROM HALTON HILLS HYDRO INC.

VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES AND RESPONSES

1.0 ADMINISTRATION (EXHIBIT 1)

1 – VECC IRR – 1

1.0-VECC-1

Reference: **Exhibit 1,page / Exhibit 2, DSP, Section 4/Exhibit 2, Appendix B**

"*In particular, customers showed a strong preference for a proactive replacement instead of run to failure.*"

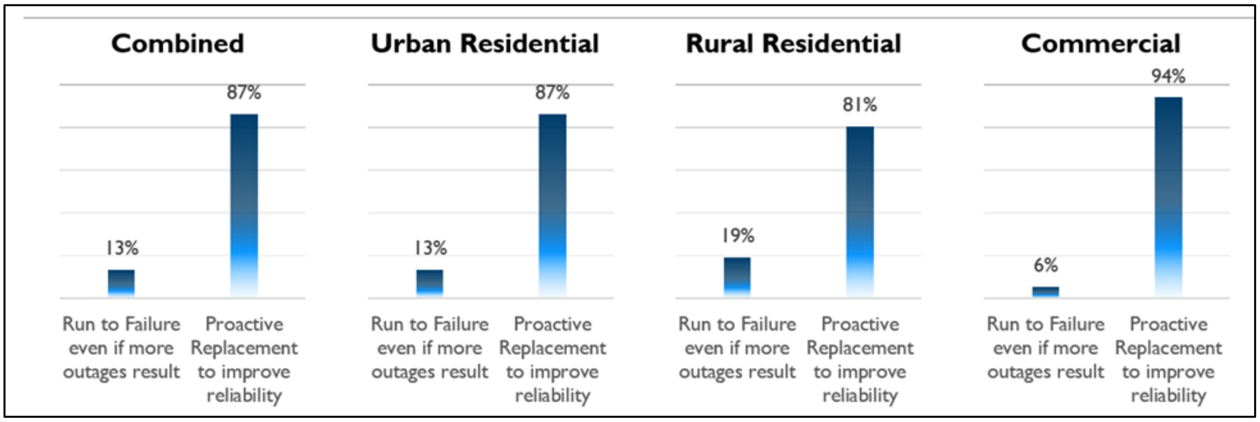
a) What assets is this finding being applied to in the proposed Distribution Asset Plan? Specifically, what are the capital cost implications of implementing this finding in the 2021 capital plan?

b) Please explain how HHHI came to this conclusion, specifically please identify the Customer Engagement Results which HHHI is relying upon for this statement.

Response:

a) The results of the customer satisfaction survey informed HHHI that customers have a strong preference for replacing aged assets rather than running the assets to failure. HHHI's Asset Management Plan SP20-01 describes HHHI's assets including those which are proactively maintain and replaced and which are run to failure. In 2021, HHHI's will be proactively replacing wood poles, poletrans transformers, porcelain insulators and switches, a substation transformer, and a live-front transformer. The capital costs are shown in Table 61 of HHHI's distribution system plan.

b) In the survey, customers were asked the following question: "Some power outages can be avoided by replacing aging equipment before it fails. This is considered a proactive replacement strategy. It can improve reliability but may also increase costs. Should we proactively replace aging equipment or wait until it fails?"
Responses were as follows:



This sentiment was also supported in HHHI's 2018 Customer Satisfaction survey. Table VECC IRR - 1 shows the prioritization given to proactive replacement.

Table VECC IRR – 1 – Survey Results (Priority Planning)

Priority Planning within the next 5 years	
Top 2 Boxes: 'very high + high priority'	**Halton Hills Hydro**
Investing more in the electricity grid to reduce outages	79%
Pro-actively maintaining and upgrading equipment	88%
Reducing response times to outages	80%
Investing more in tree trimming to help reduce the number of outages	69%
Investing in new technologies such as battery storage	54%

Source: UtilityPulse 2018 Customer Satisfaction Survey

2.0 RATE BASE (EXHIBIT 2)

2 – VECC IRR – 2

2.0-VECC-2

Reference: Exhibit 1, Table 29

a) The average capital contribution as a percentage of system access for the period 2016 through 2019 (actuals) is approximately 60%. The forecast capital contributions for the 2021 test year is approximately 45% of the estimated system access budget. Please explain how the capital contribution estimate for 2021 was derived and why the forecast amount differs significantly from the past average.

Response:

As stated in section 4.12.3.1 of HHHI's DSP, the capital contributions are forecasted based on past experience and known information at the time a budget is prepared. In 2021, HHHI's forecasted capital contribution reflects contributions from customer and developer driven projects, as well as generation connections, and municipally driven projects. The forecasted capital contributions differ from the historical average due to level of investment HHHI forecasted to address municipally driven projects during the forecast period as compared to the historical period.

2 – VECC IRR – 3

2.0-VECC-3

Reference: Exhibit 2, page 35-36, Table 29 / EB-2015-0074, Exhibit 2, Tab 2, Schedule 2, page 56

In EB-2015-0074 HHHI makes the following statement: *A significantly larger scope of Pole Trans replacements in 2014 (Lakeview Subdivision in Acton) was performed as compared to similar work on Bower Street in 2013.*

In this application HHHI explains that it "*re-evaluated the distribution to Lakeview subdivision and decided it was reasonable to expand the scope of work to include relocating overhead rear-lot distribution to underground front lot distribution to enhance reliability for customers in 24 the area that had been affected by the ice storm of December 2013.*"

a) Did the conversion to conversion underground result in any of the prior pole transformer replacements in the Lakeview subdivision being made redundant? If yes, please identify the amount of investment in prior 5 years in the Lakeview subdivision that was made redundant due to the conversion to underground.

b) Please provide the business case that was undertaken to support conversion to underground front lot. Specifically, please provide the alternative cost of rehabilitation of the existing plant (i.e. like for like).

c) The $1 million cost of this project represents over 10% of the average HHHI annual capital budget, and yet HHHI explains it was not anticipated in the 2016-2020 DSP. Please explain how it was that such a large project was unanticipated in August of 2015 (filing date of EB-2015-0074) and yet in-service by the end of 2016.

Response:

a) No, the conversion to underground did not result in any of the prior pole transformer replacements in the Lakeview subdivision being made redundant.

b) HHHI identified that the rear-lot distribution infrastructure was attached to Bell utility poles that were in a varying state of condition. In 2015, HHHI had forecasted a capital expenditure in the DSP for 2016, related to a municipally driven project, pole relocations on 9th Line to accommodate road improvements. The Region of Halton deferred the 9th Line project to a date beyond the previous DSP forecast period of 2020 leaving HHHI in a position where HHHI may not achieve the forecasted spending levels applied for. HHHI chose to mitigate this risk by proactively addressing rear-lot distribution in the Lakeview subdivision through removing HHHI infrastructure from another utilities' assets.

c) Please see HHHI's response 2 – VECC IRR -3 part b.

2 – VECC IRR – 4

2.0-VECC-4

Reference: Exhibit 2, Appendix 2-AA

a) Please revise Appendix 2-AA to show the actual 2020 capital spending to date and (separately) for forecast remaining amounts to be spent in 2020.

b) Please also show in the revised Appendix 2-AA for each asset category the actual and forecast capital contributions.

Response:

a) Please see HHHI's response 2 – Staff IRR – 38, 2 – SEC IRR – 22 and Table VECC IRR – 2.

Table VECC IRR – 2 – Actual Year to Date Capital Spending and Forecast

CATEGORY																Forecast Period (planned)				
	2016			2017			2018			2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual YTD	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	1,161	1,161	0%	886	1,587	79%	3,331	2,182	(35)%	967	1,796	86%	2,524	1,272	(50)%	2,530	1,810	3,243	2,999	2,099
System Renewal	4,120	4,991	21%	4,227	4,601	9%	2,818	4,196	49%	3,891	3,406	(13)%	2,070	1,058	(51)%	2,362	2,669	1,427	1,776	2,425
System Service	2,303	2,035	(12)%	2,411	1,574	(35)%	2,959	1,747	(41)%	3,321	2,000	(40)%	1,525	843	(55)%	882	1,111	1,424	968	1,099
General Plant	778	491	(37)%	479	793	65%	421	496	18%	425	654	54%	621	278	(45)%	828	582	607	694	618
TOTAL EXPENDITURE	**8,361**	**8,678**	**4%**	**8,004**	**8,555**	**7%**	**9,529**	**8,622**	**(10)%**	**8,605**	**7,856**	**(9)%**	**6,741**	**3,452**	**(51)%**	**6,602**	**6,172**	**6,701**	**6,437**	**6,241**
Capital Contributions	652	655	0%	596	1,483	149%	1,741	998	(43)%	711	833	17%	1,068	766	(72)%	1,135	885	1,479	1,391	997
Net Capital Expenditures	**7,709**	**8,023**	**4%**	**7,408**	**7,073**	**(5)%**	**7,788**	**7,624**	**(2)%**	**7,894**	**7,023**	**(11)%**	**5,673**	**2,686**	**(47)%**	**5,467**	**5,287**	**5,222**	**5,046**	**5,244**
System O&M	1,730	1,905	10%	1,730	1,706	(1)%	1,730	1,636	(5)%	1,730	1,570	(9)%	1,708		(100)%	1,982	2,031	2,082	2,134	2,187

b) Please see Table 47 in HHHI's DSP. Table 47 provides a summary of capital contributions for the historical period years 2016 – 2019 and for the forecast period of 2021 – 2025. HHHI's response to 2 – VECC – 4 part a provides current capital contributions to September 2020.

2 – VECC IRR – 5

2.0-VECC-5

Reference: Exhibit 2, page 60

Please explain how the 2021 "Municipally Driven Projects" amount of $939,918 is estimated.

Response:

Municipally driven projects are System Access projects that HHHI is required to uptake to meet customer requirements. The estimated costs for municipally driven projects is based on known municipal projects at the time of filing the cost of service application and accounts for HHHI's anticipated level of investment to address the known projects at the time the budget was prepared for the DSP.

2 – VECC IRR – 6

2.0-VECC-6

Reference: Exhibit 2, Table 41, page 85

a) With respect to the TS cost overruns, please explain what incremental "Commissioning Costs" are comprised of (as separate from the SCADA, labour, equipment and materials costs listed in Table 41).

Response:

a) Please see HHHI's response 2 - Staff IRR – 6.

2 – VECC IRR – 7

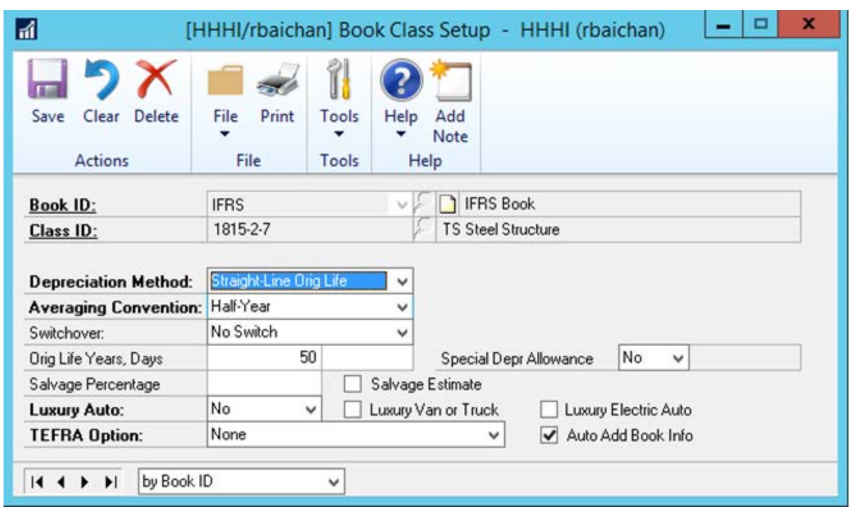
2.0-VECC-7

Reference: Exhibit 2, Section 2.3.7, page 91

a) HHHI has made two adjustments to the standard Kinectric's Report Service Life rates: Transformer Station Equipment and Administrative Buildings. Are these asset life adjustments the result of an earlier study undertaken by HHHI?

Response:

a) HHHI did not update the useful life for the Administrative Building. HHHI continues to use a forty-two (42) year useful life. This useful life was approved in HHHI's 2012 Cost of service Rate Application and has been in use since then. No change was made to the Transformer Station Equipment useful life. The twenty (20) years showing in Table 45 is incorrect and should show fifty (50) years. The fifty (50) years useful life is set up in HHHI's financial system as shown below and was used to calculate the depreciation expense included in the revenue requirement.



2 – VECC IRR – 8

2.0-VECC-8

Reference: Exhibit 2, DSP, Section 3.44, pages 182-, Section 4.6

a) Please explain and contrast the advantages and disadvantages of running polemount transformers to failure as compared to a proactive strategy for replacement of these assets. Specifically, what is HHHI's view of the cost and reliability trade-off as between a run-to-failure strategy and proactive test and replace of polemount transformers.

Response:

a) As described in HHHI's Asset Management Plan SP20-01 and DSP, HHHI does not proactively replace polemount transformers but rather practices a run to failure approach. Transformers are inherently reliable and can operate for beyond their economic useful life depending on the quality of their manufacture, location of installation, and loading. HHHI's approach to managing it's transformer assets strikes a balance between spending capital dollars on unnecessary transformer replacements, where transformers remain in good operating condition, with replacing transformers that are damaged, leaking, or have failed, thus requiring replacement.

2 – VECC IRR – 9

2.0-VECC-9

Reference: Exhibit 2, DSP, Section 4,12,2, page 252

System Renewal						
Pole Replacements	End of Life Assets	624,199	647,375	679,744	713,731	749,418
Poletrans Replacement Program	Obsolete Equipment	809,294	790,157	165,000	382,177	50,000
Porcelain Insulator Replacement Program	End of Life Assets	51,459	53,003	54,593	56,231	57,918
Transformer Replacement Program	End of Life Assets	222,791	435,329	187,889	120,525	443,241
Pole Line Rebuild Program	End of Life Assets	0	0	25,000	378,020	407,907
Substation Equipment	End of Life Assets	615,397	700,253	242,444	83,760	674,760
Distribution Equipment Renewal	End of Life Assets	38,950	42,649	72,600	41,334	42,160
Total		2,362,090	2,668,766	1,427,270	1,775,778	2,425,404

General Plant						
Equipment & Tools		525,000	265,000	330,000	295,000	435,000
Software & Systems		233,057	240,400	173,140	397,260	158,140
Building Equipment		70,000	77,000	103,800	2,000	25,000
Sub-Total		828,057	582,400	606,940	694,260	618,140

a) HHHI proposes to spend $809,294 on "Poletrans Replacement Program" in 2021 under the auspices of replacing obsolete equipment. Why could this program not be executed in a more levelized fashion over the 5-year program, that is spending approximately $440k in each year of the DSP plan?

b) Similarly, "Equipment and Tools" spending in 2021 of $525k is significantly higher than the five-year average of approximately $382k. Why could this program not be undertaken on a more evenly paced program of asset replacement?

Response:

a) As described in HHHI's Asset Management Plan SP20-01, HHHI operates poletrans transformers at varying locations in the Town of Halton Hills. Each location is unique, having a quantity of poletrans transformers reflective of the number of customers being supplied. HHHI's capital budget in 2021 reflects the level of investment HHHI forecasts to replace a portion of the remaining poletrans transformers on Rosemary Road, Division Street, and Clare Court in Acton with a forecasted completion in 2022. The level of investment proposed for completing these poletrans replacements in Acton is based on levels of investment made during the historical period and forecasted contract labour costs. The level of investment forecasted in HHHI's DSP reflects the specific locations in which HHHI intends to replace poletrans transformers. Were HHHI to levelize the spending as suggested in this questions, the replacement projects in 2021 and 2022 would take longer, thereby disturbing residents in these areas for a longer period, require additional time for making temporary connections between vintage and new assets, and potentially increase contractor costs as the work could be dis-contiguous resulting in higher costs (ex. move-in/ move-out fees).

b) The costs for 2021 include a digger derrick chassis purchase that was deferred from 2020 to 2021. This increased the fleet budget for 2021 above the more evenly paced program in place.

As shown in Exhibit 2, DSP, Page 265, Section 4.12.4.3.1. Equipment & Tools:

"… HHHI maintains a long-term vehicle maintenance strategy where smaller vehicles are replaced every 10 years and large trucks are replaced every 12 years. Other equipment such as trailers and generators are evaluated every 5 years once they reach 20 years of age and are only replaced when necessary. This long-term strategy ensures a relatively even annual budget for vehicles … Truck purchases are spread over 2 years to balance spending over a ten-year period for fleet purchasing … Following our 20-year fleet replacement plan we have a reasonably balanced dollar value budgeted for each year to avoid hills and valleys in spending while maintaining a 10-year replacement for small fleet vehicles and a 12-year replacement for large fleet vehicle formula. If a budgeted purchase is deferred for any reason, the costs associated with the deferred purchase are added to the following year's non-construction capital budget as these costs do not go away. Maintaining post end of life fleet vehicles directly affects our OM&A budget as well as creating downtime for the employees that rely on our fleet vehicles to perform their duties safely and efficiently."

2 – VECC IRR – 10

2.0-VECC-10

Reference: Exhibit 2, Section 4.12.3.1.4

The following municipally driven projects were presented at the above reference:

1. Trafalgar Road;
2. 10 Side Road/ Winston Churchill Blvd.;
3. Highway #25/ Campbellville Road.

a) Are these all the projects representing the $1,366,230 identified for 2021 under the category "Municipally Driven Projects" (System Access Appendix 2-AA)?
b) What are the forecast capital contributions for these projects?
c) Please provide an update as to the status of these projects proceeding in 2021 and include any correspondence or agreements from the affected municipalities which indicate the projects are to be completed in 2021.

Response:

a) Yes, those three (3) projects represent the Municipally Driven project budget for 2021.

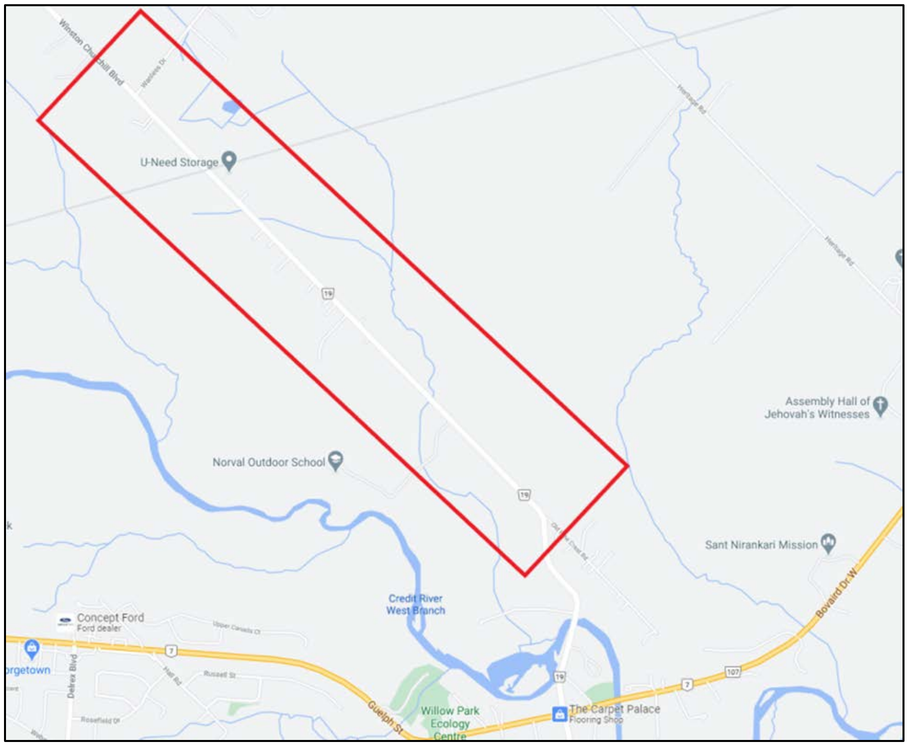
b) Forecast capital contributions for these three (3) projects total $426,312.

c) HHHI's DSP identifies the three projects highlighted by VECC in this question's preamble as potential capital projects related to municipally driven projects. These projects are subject to the municipalities' schedule and can be impacted if/ when the municipality alters their schedule. Regardless, HHHI makes its best efforts to align projects with the known information provided by the local and regional municipalities.

When HHHI prepared the DSP for the forecast period, Trafalgar Road was identified for potential relocations in 2021, hence, HHHI has budgeted for this project. It is HHHI's understanding that the Region of Halton intends to have acquired the land necessary to facilitate relocations by mid-2021. Following acquisition of lands, HHHI will be in a position to commence relocation activities related to Trafalgar Road.

The Highway #25/ Campbellville Road project is not planned for 2021. HHHI anticipates this project may proceed in 2024 based on the Region of Halton's progress and email from their project manager.

Since HHHI filed the DSP, the Region of Peel has advised HHHI that the 10 Side Road/ Winston Churchill Blvd project is currently on hold. The Region of Peel has shifted their focus to another location on Winston Churchill Blvd, north of Bovaird Drive, PR-in 2021 that will require design work from HHHI's Engineering Department relating to asset relocations to accommodate road improvements. Please see the following map illustrating the location of this project.



Winston Churchill Blvd, north of Bovaird Drive, to Wanless Drive

2 – VECC IRR – 11

2.0-VECC-11

Reference: Exhibit 2, Appendix E – Capital Projects/ Appendix 2-AA

We are unable to reconcile Appendix E with the information provided in Appendix 2-AA. For example: system service projects are not distinguished in Appendix E as to whether they are Feeder Improvements or Voltage Conversions in Appendix 2-AA. The Garage Roof Replacement of 60k in Appendix E is less the "Building Equipment" category in Appendix 2_AA. The "Automated Switches & Scada Integration amount of $243,887 in Appendix 2-AA is more than the project plan listed as "SCADA Switch/Device Integration of $203,566 at page 720 of Appendix E; etc..)

a) Please create a table using the listing of projects for 2021 in Appendix E which and reconciles with Appendix 2-AA. Or if such a table already exists in the evidence please provide the reference.

Response:

a) Please see HHHI's response 2 – Staff IRR – 38 part b.

2– VECC IRR – 12

2.0-VECC -12

Reference: Exhibit 2, pages 99-104
Exhibit 3 page 30

Preamble: The Application states:
"*HHHI calculated the cost of power for the 2020 Bridge Year and the 2021 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Prices. Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, HHHI will update the electricity prices in the forecast*".

a) Please reconcile the kWh values by rates class used in the calculation of the cost of power commodity charges with the load forecast set out in Exhibit 3. In doing so, please demonstrate that the kWh usage associated with HHHI's Market Participant(s) has been excluded from the calculation of the commodity costs.

b) Are charges for transmission service paid directly by the Market Participant(s) to the IESO or to HHHI through the RTSRs? If the former, please demonstrate that the power usage by HHHI's Market Participant(s) has been excluded from the determination of the Transmission Costs included in the Cost of Power.

Response:

a) As shown in Table VECC IRR – 3, the Cost of Power Commodity and the Load Forecast kWhs reconcile when the Load Forecast is adjusted by the proposed Loss Factor of 1.0400.

Table VECC – IRR – 3 – Reconciliation between Cost of Power and Load Forecast

Rate Class	2021 Test Year Load Forecast	Loss Adjusted Load Forecast	Cost of Power Commodity
Loss Factor		**1.0400**	
Residential			
kWh	207,178,634	215,465,779	215,465,779
General Service < 50 kW			
kWh	46,722,885	48,591,800	48,591,800
General Service 50 to 999 kW			
kWh	132,955,988	138,274,228	138,274,228
General Service 1,000 to 4,999 kW			
kWh	70,322,012	73,134,892	73,134,892
Sentinel Lights			
kWh	251,879	261,954	261,954
Street Lights			
kWh	979,604	1,018,788	1,018,788
Unmetered Scattered Loads			
kWh	962,029	1,000,511	1,000,511
Total kWhs	**459,373,031**	**477,747,952**	**477,747,952**

b) Transmission charges are paid to HHHI through the RTSRs.

3.0 OPERATING REVENUE (EXHIBIT 3)

3 – VECC IRR – 13

3.0-VECC-13

Reference: **Exhibit 3, page 6**

Preamble: The Application (page 6) states: "*With the assistance of Borden, Ladner and Gervais, LLP, HHHI used the same regression analysis methodology approved by the Ontario Energy Board (the "OEB" or "Board") in the 2016 HHHI Cost of Service ("COS") application (EB-2015-0074).*".

a) Please clarify whether, in its EB-2015-0074 Decision, the OEB: i) actually approved HHHI's load forecast methodology or ii) accepted the load forecast included in the Settlement Proposal filed during the proceeding.

Response:

a) HHHI is not in a position to clarify the Board Decision. HHHI can state that HHHI has used a regression analysis methodology which was approved not only in HHHI's previous cost of service but also in countless of previous rate application. HHHI notes that the methodology is also a requirement of the OEB.

3 – VECC IRR – 14

3.0-VECC-14

Reference: **Exhibit 3, pages 7-8 and 22-23**
Load Forecast Model, Rate Class Energy Model Tab

a) Is the methodology used to translate historical use by customer class into weather normal historical use by class (Table 2) the same as the methodology used to translate the non-weather normal 2021 forecasts by customer class into the forecast 2021 weather normalized values?

Response:

a) The forecast of billed energy by rate class is developed based on a forecast of customer/ connections numbers and the 2019 usage patterns per customer/ connection. With respect to Table 2, the Billed Energy Actuals are multiplied by the Weather Normal Conversion Factor from Table VECC IRR - 4 (cells highlighted as an example).

Table VECC IRR – 4 – Replicated Exhibit 3 Table 2 – Billed Energy by Rate Class

YEAR	RESIDENTIAL	GENERAL SERVICE LESS THAN 50 KW	GENERAL SERVICE 50 TO 999 KW	GENERAL SERVICE 1,000 TO 4,999 KW	SENTINEL LIGHTS	STREET LIGHTS	UNMETERED SCATTERED LOADS	TOTAL
BILLED ENERGY (GWH) - ACTUAL								
2010	215.0	54.8	115.5	102.2	0.6	2.7	0.9	491.8
2011	208.2	57.0	114.8	105.3	0.4	2.7	0.9	489.4
2012	213.8	56.9	112.0	101.7	0.4	2.8	0.9	488.5
2013	207.8	56.9	115.1	111.6	0.4	2.8	0.9	495.5
2014	203.4	51.5	126.1	116.7	0.4	2.8	0.9	501.8
2015	203.4	50.7	140.1	112.1	0.3	2.8	0.9	510.2
2016	204.4	51.3	137.3	107.2	0.3	1.8	0.9	503.2
2017	193.7	50.5	135.4	99.3	0.3	1.1	0.9	481.2
2018	208.4	52.0	144.9	91.8	0.3	1.1	1.0	499.4
2019	202.1	50.7	150.4	88.6	0.3	1.0	1.0	494.0
BILLED ENERGY (GWH) - WEATHER NORMAL								
2010	214.8	54.7	115.4	102.1	0.6	2.7	0.9	491.1
2011	207.7	56.8	114.5	105.0	0.4	2.7	0.9	488.1
2012	213.4	56.9	111.8	101.6	0.4	2.8	0.9	487.8
2013	209.6	57.4	116.1	112.6	0.4	2.8	0.9	499.9
2014	205.5	52.1	127.4	117.9	0.5	2.8	0.9	507.1
2015	204.5	51.0	140.8	112.7	0.3	2.8	0.9	513.0
2016 BOARD APPROVED	205.6	59.0	136.6	112.2	0.5	1.5	0.9	516.2
2016	200.9	50.4	134.9	105.3	0.3	1.8	0.9	494.6
2017	195.9	51.1	136.9	100.4	0.3	1.1	0.9	486.7
2018	204.9	51.1	142.4	90.3	0.3	1.1	0.9	490.9
2019	202.9	50.9	151.0	89.0	0.3	1.0	1.0	495.9
2020 BRIDGE YEAR	205.2	47.2	136.9	72.2	0.3	1.0	1.0	463.7
2021 TEST YEAR	207.2	46.7	133.0	70.3	0.3	1.0	1.0	459.4

Table VECC IRR – 5 – Replicated Exhibit 3 Table 6 – Total System Purchases Excluding Wholesale Market Participants

YEAR	ACTUAL	PREDICTED	% DIFFERENCE	PREDICTED WEATHER NORMAL	WEATHER NORMAL CONVERSION FACTOR	ACTUAL WEATHER NORMAL
		PURCHASED ENERGY (GWH)				
2010	525.7	525.6	(0.0%)	525.0	0.9987	525.0
2011	524.3	524.0	(0.1%)	522.6	0.9975	523.0
2012	516.9	521.2	0.8%	520.4	0.9984	516.1
2013	523.4	520.2	(0.6%)	524.8	1.0088	528.0
2014	534.3	529.6	(0.9%)	535.2	1.0106	539.9
2015	528.8	527.5	(0.2%)	530.4	1.0055	531.7
2016	525.6	532.2	1.3%	523.0	0.9827	516.5
2017	499.0	507.7	1.7%	513.4	1.0113	504.6
2018	519.3	517.6	(0.3%)	508.8	0.9829	510.4
2019	513.3	505.0	(1.6%)	507.0	1.0040	515.3
2020 BRIDGE YEAR		508.6		508.6	1.0000	
2021 TEST YEAR		507.2		507.2	1.0000	
2021 TEST - 20 YR TREND		507.9				

For weather sensitive load, the billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression analysis.

3 – VECC IRR – 15

3.0-VECC-15

Reference: **Exhibit 3, pages 14 and 18**
Load Forecast Model (COS), Purchased Power Model Tab

Preamble: The Application states: "*An equation to predict total system purchased energy is developed using a multivariate regression model with the independent variables outlined below.*"
In the Load Forecast Model (Purchased Power Model Tab) there is no column for HHHI purchases from embedded generators.

a) Please confirm that dependent variable used in the regression equation (i.e., Column D in the Purchased Power Model Tab) is the sum of IESO power purchase by HHHI and usage by HHHI's Market Participant customer(s).
b) Does HHHI purchase power from any embedded generators (e.g. microFit customers)? If yes, are these purchases included in the purchased power values used as the independent variable in the regression analysis?
   i. If purchases from embedded generators have not been included, please update the load forecast model and results accordingly.
c) With respect to Table 6 (page 18), please confirm that – contrary to the title of the Table – the actual purchase values shown include usage by the Market Participant(s). (Note: The values reconcile with Column D -the sum of IESO purchases and Market Participant(s) use in the Purchased Power Model Tab).
d) With respect to Table 6, please confirm that the predicted purchased power values for 2020 and 2021 include usage by the Market Participant(s).
e) Please provide the 2020 and 2021 predicted power purchases excluding usage by HHHI's Market Participant(s) and explain how they were derived.

Response:

a) Confirmed.

b) The consumption related to microFIT is included in the IESO consumption.

c) Confirmed. Table 6 does indeed include wholesale market participants (column D of the Power Purchase Model Tab).

d) Confirmed.

e) Table VECC IRR – 6 shows the predicted weather normal consumption excluding HHHI's wholesale market participant.

Table VECC IRR – 6 - Total System Purchases Excluding Wholesale Market Participants

YEAR	ACTUAL	PREDICTED	% DIFFERENCE	PREDICTED WEATHER NORMAL	WEATHER NORMAL CONVERSION FACTOR	ACTUAL WEATHER NORMAL
PURCHASED ENERGY (GWH)						
2010	520.5	520.5	(0.0%)	519.3	0.9977	519.3
2011	519.2	518.9	(0.1%)	517.4	0.9969	517.7
2012	512.1	516.2	0.8%	515.8	0.9991	511.6
2013	518.5	515.4	(0.6%)	519.5	1.0080	522.7
2014	529.5	524.9	(0.9%)	527.9	1.0058	532.6
2015	524.4	522.9	(0.3%)	524.1	1.0022	525.5
2016	521.3	527.8	1.2%	518.3	0.9820	511.9
2017	494.8	503.6	1.8%	510.6	1.0138	501.7
2018	515.3	513.7	(0.3%)	506.9	0.9867	508.4
2019	509.5	501.1	(1.6%)	505.4	1.0086	513.8
2020 BRIDGE YEAR		504.7		506.7	1.0038	
2021 TEST YEAR		503.3		505.4	1.0041	
2021 TEST - 20 YR TREND		504.0				

3 – VECC IRR – 16

3.0-VECC-16

Reference: Exhibit 3, page 15

a) Please confirm that the -1.5 coefficient for CDM means for every kWh of persisting CDM monthly purchases are reduced by 1.5 kWh.

b) In HHHI's view does this result make sense intuitively and, if yes, why?

c) Please provide an alternative purchased power model (i.e., coefficients and statistical results) along with the resulting 2020 and 2021 load forecast where:

   i. The monthly purchased power values used to estimate the regression equation are increased by the persisting monthly CDM and the regression equation is estimated using the balance of the explanatory variables as set out in the Application.

   ii. The 2020 and 2021 monthly purchases are first forecast using this regression model and the forecast values for the explanatory variables per step (i).

   iii. The resulting 2020 and 2021 forecast monthly purchases are reduced by the persisting CDM forecast for each month as set in the Application.

d) It is noted that the regression model does not include any independent variables related to the level of economic activity (e.g., employment levels or GDP levels) or number of customers/connections. Did HHHI test any such variables to determine whether their "coefficients" were statistically significant and their inclusion improved the overall model?

   i. If not, why not?

   ii. If yes, what variables were tested and what were the results?

Response:

a) Confirmed.

b) Regression predictors are not considered independently, but in context of each other as a whole. The separate variables influence each other's effect on the response variable, and positive or negative associations can be flipped in the presence of other variables. HHHI is of the view that the effects of conservation and demand side management should intuitively result in a reduction in load and as such a negative coefficient therefore it's not abnormal.

c) The requested scenario is filed in conjunction with these responses (Halton_Att_3-VECC-16c_LoadForecastScenarios_20201125). Please see Table VECC IRR – 7 for the requested scenario.

Table VECC IRR – 7 – Alternate Scenario

YEAR	RESIDENTIAL	GENERAL SERVICE LESS THAN 50 KW	GENERAL SERVICE 50 TO 999 KW	GENERAL SERVICE 1,000 TO 4,999 KW	SENTINEL LIGHTS	STREET LIGHTS	UNMETERED SCATTERED LOADS	TOTAL
NON-NORMALIZED WEATHER BILLED ENERGY FORECAST (GWH)								
2020 BRIDGE YEAR	203,957,742	51,377,934	150,365,345	88,636,118	251,879	979,604	962,029	496,530,651
2021 TEST YEAR	205,821,441	52,111,528	150,365,345	88,636,118	251,879	979,604	962,029	499,127,944
WEATHER ADJUSTMENT (GWH)								
2020 BRIDGE YEAR	2,688,382	677,216	1,486,483	221,104	0	0	0	5,073,186
2021 TEST YEAR	698,452	176,840	382,697	56,924	0	0	0	1,314,912
ADJUSTMENT FOR GENERAL SERVICE 1,000 TO 4,999 KW CUSTOMERS (GWH)								
2020 BRIDGE YEAR			1,018,590	(9,608,748)				(8,590,157)
2021 TEST YEAR			1,018,590	(9,608,748)				(8,590,157)
COVID-19 ADJUSTMENT								
2020 BRIDGE YEAR	8,073,327	(2,440,452)	(10,713,531)	(6,315,323)	0	0	0	(11,395,979)
2021 TEST YEAR	10,291,072	(3,126,692)	(13,532,881)	(7,977,251)	0	0	0	(14,345,751)
WEATHER NORMALIZED BILLED ENERGY FORECAST (GWH)								
2020 BRIDGE YEAR	214,719,451	49,614,699	142,156,887	72,933,152	251,879	979,604	962,029	501,603,837
2021 TEST YEAR	216,810,965	49,161,676	138,233,751	71,107,044	251,879	979,604	962,029	500,442,856

Table VECC IRR – 8 – Alternate Scenario

	2020 WEATHER NORMAL	2021 WEATHER NORMAL
ACTUAL KWH PURCHASES		
PREDICTED KWH PURCHASES	546,195,217	544,931,028
% DIFFERENCE		
COVID ADJUSTMENT	(12,409,054)	(15,621,054)
DIRECT CDM ADJUSTMENT	(9,353,802)	(9,353,802)
NET PURCHASES	524,432,361	519,956,172
BILLED KWH	481,617,701	477,506,948
BY CLASS		
RESIDENTIAL		
CUSTOMERS	20,663	20,852
KWH	214,719,451	216,810,965
GS<50		
CUSTOMERS	1,850	1,876
KWH	49,614,699	49,161,676
GS>50 TO 999		
CUSTOMERS	219	219
KWH	142,156,887	138,233,751
KW	396,699	385,777
GS> 1000 TO 4999		
CUSTOMERS	9	9
KWH	72,933,152	71,107,044
KW	174,827	170,313
SENTINELS		
CONNECTIONS	175	175
KWH	251,879	251,879
KW	680	680
STREETLIGHTS		
CONNECTIONS	4,833	4,833
KWH	979,604	979,604
KW	3,105	3,105
USL		
CONNECTIONS	183	183
KWH	962,029	962,029
TOTAL OF ABOVE		
CUSTOMER/CONNECTIONS	27,932	28,147
KWH	481,617,701	477,506,948
KW FROM APPLICABLE CLASSES	575,310	559,875
TOTAL FROM MODEL		
CUSTOMER/CONNECTIONS	27,932	28,147
KWH	481,617,701	477,506,948
KW FROM APPLICABLE CLASSES	575,310	559,875
CHECK SHOULD ALL BE ZERO		
CUSTOMER/CONNECTIONS	0	0
KWH	0	0
KW FROM APPLICABLE CLASSES	0	0
METERED CUSTOMERS	23,100	23,315
AVERAGE CUSTOMERS	22,994	23,208

d) As stated in Exhibit 3.2.1 page 6, "the Number of Customers variable was eliminated since it had a non-intuitive negative coefficient. The estimated monthly CDM activity was included as a variable and not added to the power purchase amount as was done in the 2016 COS application. This allowed the negative coefficient assigned to the Number of Customers variable to be reassigned to a variable in an intuitive manner. HHHI was also concerned with the process used in the 2016 COS application of adding the monthly CDM activity to the power purchased amount as it produced a total billed 2016 kWh amount that was never achieved on an actual and weather normal basis from 2016 to 2019. Additionally, by using the CDM monthly activity as a variable, a slightly better statistical result was produced.

   The Number of Customers variable was tested, resulting in a non-intuitive negative coefficient.

3 – VECC IRR – 17

3.0-VECC-17

Reference: **Exhibit 3, pages 8 and 20-21**

Preamble: The Application states (page 20): "*For the Residential and General Service less than 50 kW classes, the growth factor resulting from the geometric mean analysis from 2010 to 2019 is applied to the 2019 customer numbers to determine the forecast of customer / connections for 2020. Then the factor is applied again to 2020 Bridge Year forecast to determine the 2021 Test Year forecast. For all other classes, HHHI has assumed the number of customers / connections will remain at the 2019 level in 2020 and 2021.*"
The Application (page 8) states: "*Customer/Connection values are on a year-end basis and Streetlighting, Sentinel Lights and Unmetered Scattered Loads are measured as connections. The customer/connection values are converted to an average basis for the purposes of rate design.*"

a) Please provide the actual customer/connection counts by customer class for June 2020 and July 2020.
b) Please explain how the "average count" was calculated for the purposes of rate design.

Response:

a) HHHI has actual customer / connection counts by class for June 2020 and September 2020 at this time. The counts are shown in Table VECC IRR - 9.

Table VECC IRR – 9 – Customer Counts at June and September 2020

Rate Class	Jun-20	Sep-20
Residential	20,503	20,499
General Service less than 50 kW	1,788	1,800
General Service 50 to 999 kW	226	228
General Service 1,000 to 4,999 kW	10	10
Unmetered Scattered Load	182	182
Sentinel Lights	175	175
Street Lighting	4846	4846
microFIT	179	179
Total	**27,909**	**27,919**

b) For rate design purposes, the previous year end final numbers and the current year end final numbered are averaged.

3 – VECC IRR – 18

3.0-VECC-18

Reference: Exhibit 3, page 24

a) The Application makes adjustments to the load forecast for 2021 related to three specific customers. (e.g., average of 12 monthly values). What criteria did HHHI use in order to determine that specific adjustments were required only for these three cases?
b) Are there any GS 50-999 or GS 1,000-4,999 customers whose usage in the first three months of 2020 was 10% or more greater than in the first three months of 2019? If, yes, how many customers met this criteria and what was the increase usage over the three months for each class related to these specific customers?
c) With respect to Customer 1, please explain the basis for the 9,108 kW billing demand adjustment.

Response:

a) HHHI was made aware, prior to the 2021 Cost of Service Application, that the load loss from the three (3) customers would be significant, thus requiring separate adjustments to the load forecast.

b) HHHI was unsure if VECC was requesting the kWh or kW variances, therefore, HHHI has provided both. Table VECC IRR – 10 indicates the number of customers, by class (General Service 50 to 999 kW and General Service 1,000 to 4,999 kW) whose usage in the first three (3) months of 2020 was greater than 10% or more than in the first three (3) months of 2019.

HHHI would like VECC to note that Table VECC IRR – 10 also includes the number of customers by class (General Service 50 to 999 kW and General Service 1,000 to 4,999 kW) whose usage in the first three (3) months of 2020 was less than 10% or more than in the first three (3) months of 2019.

Additionally, HHHI has included Table VECC IRR – 10 which represents those accounts shown in Table VECC IRR – 11 that had both the kWhs and kWs affected by greater than 10% (increase and decrease).

Table VECC IRR – 10 – Number of Accounts with a variance of more than +/- 10 % between Q1 2019 and Q1 2020 (kWhs OR kWs OR both)

Rate Class	Greater than 10% INCREASE		Greater than 10% DECREASE	
	kWh	kW	kWh	kW
General Service 50 to 999 kW	35	21	52	41
General Service 1,000 to 4,999 kW	1	1	0	3

Table VECC IRR – 11 – Number of Accounts with a Variance of more than +/- 10 % between Q1 2019 and Q1 2020 (kWhs and kWs)

Rate Class	Greater than 10% INCREASE	Greater than 10% DECREASE
General Service 50 to 999 kW	18	28
General Service 1,000 to 4,999 kW	1	0

c) The estimated customer 1 NET Demand is 758.8kW per month as shown below from the consultant's report. The total is 758.8 * 12 months = 9,108 kW.

		Notes	
Pre Project Demand Savings (kW)	1,200.0	Description	
Pre-Project Consumption Savings (kWh)	5,000,000.0		
		Net to Gross Ratio - kWh	0.79225
Post Project Demand Savings		Estimated NET Energy (kWh)	3,169,000.0
Post Project Consumption Savings		NET Energy (kWh)	0.0

Net to Gross Ratio - kW	0.79042
Estimated NET Demand (kW)	758.8
NET Demand (kW)	0.0

3 – VECC IRR – 19

3.0-VECC-19

Reference: Exhibit 3, pages 25-27

a) Please provide a schedule that sets out the HDD and CDD values for: i) the period April 1, 2019 to September 30, 2019 and ii) the period April 1, 2020 to September 30, 2020.

b) Please provide a schedule that sets out HHHI's actual monthly power purchases for April through September 2020, using the same definition of power purchases as used in the load forecast model.

c) Using the actual Heating and Cooling Degree Days per part (b), HHHI's purchase power model (per Purchased Power Model Tab), HHHI's 2020 forecast for the explanatory variables please provide the resulting prediction for the power purchased for the months of April through September 2020.

d) Please provide a revised version of Table 17 where the COVID-19 adjustment is applied to the predicted billed energy by class after weather normalization and the specific GS customer adjustments.

e) Please confirm that the forecast set out in Table 17 assumes that the impacts experienced to date from the COVID-19 pandemic will continue for the balance of 2020 and all of 2021. What is the basis for this assumption?

f) Is it HHHI's assumption that none of the COVID-19 pandemic impacts it has incorporated in its 2021 load forecast will be addressed by the Deferral Accounts the Board has established in Response to the COVID-19 Emergency?

   i. If yes, what is the basis for this assumption?

   ii. If no, why is the COVID-19 adjustment required?

g) What would be the 2021 distribution revenue at existing (2020) rates based on the load forecast without the COVID-19 adjustments?

Response:

a) Please see Table VECC IRR – 12.

Table VECC IRR – 12 – HDD & CDD Days

2020	HEAT DEG DAYS (°C)	COOL DEG DAYS (°C)
January	605	0
February	611.8	0
March	458.7	0
April	362.3	0
May	208.1	24.2
June	23.8	97.7
July	0	215.7
August	0.8	126.7
September	69.1	33.3
October	270.3	0

b) Please see Table VECC IRR – 13.

Table VECC IRR – 13

2020	UNITS	RESIDENTIAL	GS<50	USML	GS 50-999 KWS	WMP	GS 1000-4999 KWS	STREET	SENTINEL	TOTALS
January	kWhs	18,037,843	4,523,740	81,878	12,824,692	278,057	6,849,563	119,571	19,749	42,735,091
	kWs	-	-	-	31,942	532	13,987	264	51	46,776
February	kWhs	16,470,437	4,232,368	79,592	12,188,505	255,571	6,475,506	103,677	20,862	39,826,517
	kWs	-	-	-	33,528	493	14,134	264	55	48,474
March	kWhs	16,668,732	4,046,409	79,590	12,138,263	274,696	7,544,250	98,384	21,327	40,871,651
	kWs	-	-	-	33,617	561	19,178	264	56	53,675
April	kWhs	15,662,509	3,326,788	79,593	10,103,640	258,109	6,402,609	83,356	19,732	35,936,336
	kWs	-	-	-	27,375	557	17,573	264	52	45,821
May	kWhs	17,405,844	3,364,688	79,592	10,893,687	302,877	7,688,285	75,686	21,360	39,832,017
	kWs	-	-	-	33,587	729	19,756	264	56	54,392
June	kWhs	21,295,133	3,689,787	79,593	11,712,792	340,582	8,227,624	68,113	20,223	45,433,847
	kWs	-	-	-	35,398	725	20,290	264	53	56,730
July	kWhs	24,462,809	4,281,696	79,592	13,014,856	398,366	8,807,514	73,145	20,066	51,138,044
	kWs	-	-	-	35,517	823	20,842	264	53	57,499
August	kWhs	22,001,766	4,122,972	79,592	12,329,370	388,081	8,415,296	82,389	21,412	47,440,878
	kWs	-	-	-	36,403	776	20,184	264	56	57,683
September	kWhs	16,287,402	3,884,013	79,593	11,534,370	332,339	7,836,159	91,123	20,058	40,065,058
	kWs	-	-	-	34,368	708	19,523	264	53	54,916

c) See Halton_Att_3-VECC-19c_LoadForecastScenarios_20201125.

d) Please see Table VECC IRR – 14 for the requested scenario.

Table VECC – IRR – 14 – Alternate Scenario

YEAR	RESIDENTIAL	GENERAL SERVICE LESS THAN 50 KW	GENERAL SERVICE 50 TO 999 KW	GENERAL SERVICE 1,000 TO 4,999 KW	SENTINEL LIGHTS	STREET LIGHTS	UNMETERED SCATTERED LOADS	TOTAL
NON-NORMALIZED WEATHER BILLED ENERGY FORECAST (GWH)								
2020 BRIDGE YEAR	203,957,742	51,377,934	150,365,345	88,636,118	251,879	979,604	962,029	496,530,651
2021 TEST YEAR	205,821,441	52,111,528	150,365,345	88,636,118	251,879	979,604	962,029	499,127,944
WEATHER ADJUSTMENT (GWH)								
2020 BRIDGE YEAR	(4,904,507)	(1,235,469)	(2,711,841)	(403,368)	0	0	0	(9,255,186)
2021 TEST YEAR	(7,023,406)	(1,778,242)	(3,848,275)	(572,405)	0	0	0	(13,222,329)
ADJUSTMENT FOR GENERAL SERVICE 1,000 TO 4,999 KW CUSTOMERS (GWH)								
2020 BRIDGE YEAR			1,018,590	(9,608,748)				(8,590,157)
2021 TEST YEAR			1,018,590	(9,608,748)				(8,590,157)
COVID-19 ADJUSTMENT								
2020 BRIDGE YEAR	8,073,327	(2,440,452)	(10,713,531)	(6,315,323)	0	0	0	(11,395,979)
2021 TEST YEAR	10,291,072	(3,126,692)	(13,532,881)	(7,977,251)	0	0	0	(14,345,751)
WEATHER NORMALIZED BILLED ENERGY FORECAST (GWH)								
2020 BRIDGE YEAR	207,126,561	47,702,014	137,958,563	72,308,679	251,879	979,604	962,029	487,275,466
2021 TEST YEAR	209,089,107	47,206,594	134,002,778	70,477,715	251,879	979,604	962,029	485,905,616

Table VECC IRR – 15 – Alternate Scenario

	2020 WEATHER NORMAL	2021 WEATHER NORMAL
ACTUAL KWH PURCHASES		
PREDICTED KWH PURCHASES	512,420,086	510,979,548
% DIFFERENCE		
COVID ADJUSTMENT	(11,984,040)	(15,086,028)
DIRECT CDM ADJUSTMENT	(9,033,431)	(9,033,431)
NET PURCHASES	491,402,615	486,860,090
BILLED KWH	467,289,329	462,969,707
BY CLASS		
RESIDENTIAL		
CUSTOMERS	20,663	20,852
KWH	207,126,561	209,089,107
GS<50		
CUSTOMERS	1,850	1,876
KWH	47,702,014	47,206,594
GS>50 TO 999		
CUSTOMERS	219	219
KWH	137,958,563	134,002,778
KW	385,011	373,998
GS> 1000 TO 4999		
CUSTOMERS	9	9
KWH	72,308,679	70,477,715
KW	173,283	168,758
SENTINELS		
CONNECTIONS	175	175
KWH	251,879	251,879
KW	680	680
STREETLIGHTS		
CONNECTIONS	4,833	4,833
KWH	979,604	979,604
KW	3,105	3,105
USL		
CONNECTIONS	183	183
KWH	962,029	962,029
TOTAL OF ABOVE		
CUSTOMER/CONNECTIONS	27,932	28,147
KWH	467,289,329	462,969,707
KW FROM APPLICABLE CLASSES	562,079	546,540
TOTAL FROM MODEL		
CUSTOMER/CONNECTIONS	27,932	28,147
KWH	467,289,329	462,969,707
KW FROM APPLICABLE CLASSES	562,079	546,540
CHECK SHOULD ALL BE ZERO		
CUSTOMER/CONNECTIONS	0	0
KWH	0	0
KW FROM APPLICABLE CLASSES	0	0
METERED CUSTOMERS	23,100	23,315
AVERAGE CUSTOMERS	22,994	23,208

e) Confirmed. As explained throughout the exhibit, the assumption was based on the IESO webinar entitled "An overview of COVID-19 impacts on electricity system operations". The IESO is the Crown corporation responsible for operating the electricity market and directing the operation of the bulk electrical system in the province of Ontario. As such, HHHI relies on its expertise in terms of observation and forecast. HHHI is of the opinion that the current class specific behaviour is not likely to change and instead is likely to continue until there is a significant and game changing development in the eradication of Covid-19.

f) HHHI confirms that it does nor foresee incorporating any Load Forecast related impacts in the OEB established Deferral Accounts. The impacts would be factored into its load forecast and rates and therefore would not be eligible for recovery through the Deferral Account.

g) The 2021 distribution revenue at existing (2020) rates based on the load forecast, without the COVID-19 adjustments, is shown in Table VECC IRR – 16.

Table VECC IRR – 16 – 2021 Distribution Revenue at non-COVID-19 Adjusted Load Forecast

Rate Class	Distribution Revenue at Existing Rates without COVID-19 Adjustment
Residential	6,810,124
General Service less than 50 kW	1,185,313
General Service 50 to 999 kW	1,804,447
General Service 1,00 to 4,999 kW	572,312
Sentinel Lights	45,848
Street Lighting	143,020
Unmetered Scattered Load	23,504
TOTAL	**10,584,568**

3 – VECC IRR – 20

3.0-VECC-20

Reference: **Exhibit 3, pages 16 and 23**
Load Forecast Model (COS), CDM Tab
Participation and Cost Report, April 2019, LDC Progress Tab

a) Please provide a copy of the OPA Report that supports the CDM savings values used in the CDM Tab (Rows 3-7) for the years 2006-2010.
b) Please provide a copy of the IESO Report that supports the CDM savings values use in the CDM Tab (Rows 8-11) for the years 2011-2014.
c) The Participation and Cost Report (LDC Progress Tab) shows 3,287.6 MWH of savings in 2018 from 2018 programs. However, the CDM Activity Tab only shows 2,745.9 MWh. Please reconcile.
d) Given that the savings from 2018, 2019 and 2020 programs included in the load forecast (CDM Tab, Rows 15-17) are unverified results why isn't it necessary to have an LRAMVA threshold for 2021 that reflects the level of savings included from these years' programs?

Response:

a) Please see Halton_Att_3-VECC-20a_2006-2010OPAReport_20201125.

b) Please see Halton_Att_3-VECC-20b1_2011-2014IESOReport_20201125 and Halton_Att_3-VECC-20b2_2011-2014IESOPersistence_20201125.

c) HHH is not proposing to revise the load forecast based on a correction to this value as the impacts are not expected to be material.

d) Savings related to the projects are included because HHH anticipates the projects will be completed and the energy and demand savings will be realized. Including these amounts is consistent with the Board's expectations that an LDC should include the impacts of anticipated CDM to ensure that its customers are realizing the impacts of conservation at the earliest date possible and mitigate future variances between forecasted revenue losses and actual revenue losses. HHH believes the load forecast would be overstated if the savings are not included and, as a result, future variances between forecast and actual lost revenues would increase if the amounts are removed.

3 – VECC IRR – 21

3.0-VECC-21

Reference: Exhibit 3, pages 50-51

a) Why are there no revenues shown for Retail Services (#4082) or Service Transaction Requests (#4084)?

Response:

a) Other Operating Revenue for the 2021 Test Year presented in Table -31, Appendix 2-H is different than the amount used to calculate revenue requirement. The revenue requirement presented in Exhibit 6, page 8, shows Other Operating Revenue as $1,293,382 as opposed to $1,212,222 presented in Appendix 2-H. The amount of $1,293,382 used to calculate revenue requirement includes $11,000 for Retail Services (USofA 4082) and $160 for Service Transaction Requests (USofA 4084). Also included in the amount is $70,000 for SSS Administration Revenue (USofA 4086). HHHI will update it revenue requirement to remove the $70,000 from other operating income.

3 – VECC IRR – 22

3.0-VECC-22

Reference: Exhibit 3, pages 54-55

a) Why is 2019 the only year in which there are revenues from Hydro One for the administration of the Affordability Trust Fund?
b) Where is the OM&A associated with Other Utility Operating-Recoverable Work and the administration of the Affordability Trust Fund recorded?
c) With respect to Other Utility Operating-Recoverable Work, please provide the actual associated OM&A for 2016 and the forecasted associated OM&A for 2021.

Response:

a) HHHI did not include any revenue for the administration of the Affordability Trust Fund for the 2021 Test Year. HHHI does not anticipate the Affordability Trust Fund will continue into 2021 as this a temporary program to assist customers.

b) The OM&A associated with Other Utility Operating-Recoverable Work and the administration of the Affordability Trust Fund is recorded in the income statement as operating expenses.

c) HHHI does not track costs to granular level by each revenue line and as result is unable to provide the information requested.

4.0 OPERATING COSTS (EXHIBIT 4)

4 – VECC IRR – 23

4.0 -VECC -23

Reference: Exhibit 4, pages 31-

Table 15 - Summary of Climate Change Plan

Description	Amount
Supporting Low-Carbon Mobility	$66,700
Preparing for EV Charging Impacts	$80,000
Renewable / Low-Carbon Energy	$20,000
Energy Conservation Initiatives	$60,000
Climate Change Coordinator	$53,000
Total	**$279,700**

a) Under what legislative or other legal mandate is HHHI required to participate in the "climate change emergency" declared by the Town of Halton Hills? Please provide the specific municipal bylaw or other legislation HHHI is relying upon to support this requirement.

b) Please provide the cost-benefit analysis that was undertaken in support of HHHI's Climate Change Proposal.

c) Please identify any capital spending undertaken or planned within the rate plan term for this initiative. Please provide the references in the filed Distribution System Plan for these initiatives.

d) Are any employees previously assigned to CDM responsibilities now be assigned to the Climate Change Proposal initiatives? If so please identify how many.

Response:

a) Please see HHHI's response 1 – DRC IRR – 2 part a.

b) The benefits of HHHIs Climate Change Plan are in being prepared for the future and addressing climate change. As mentioned in the response to part a, the precedent has been set in other jurisdictions and HHHI as a progressive and innovative utility is collaborating with the Town of Halton Hills to address the climate change emergency.

c) These initiatives are part of HHHI's OM&A budget.

d) No employees previously assigned to CDM responsibilities will be assigned to the Climate Change Proposal initiatives.

4 – VECC IRR – 24

4.0 -VECC -24

Reference: Exhibit 4, Appendix 2-K, page 51-52

a) Please amend Appendix 2-K to include two rows showing the total amount of OM&A capitalized and expensed in each year.
b) Do the FTEs shown in years 2016 through 2019 include any staff employed on CDM initiatives?
c) What is the current FTE compliment at HHHI?

Response:

a) Please see HHHI's response 2 – SEC IRR – 24.

b) The FTEs shown in years 2016 through 2019 do not include any staff employed on CDM initiatives.

c) The current FTE complement is 49.75 with three (3) vacant positions to be filled.

4 – VECC IRR – 25

4.0 -VECC -25

Reference: Exhibit 4, page 38

Table 17 - Transformer Station Incremental OM&A Costs

Transformer Station Costs	2019	2020	2021
Control Room and Station Maintenance		$73,050	$90,000
Expendable Materials		$1,300	$1,300
Fibre Cable, Internet, Phone Line and Security	$1,086	$16,300	$16,530
Property Tax		$43,030	$44,321
Snow Removal		$4,000	$4,000
Building Maintenance		$1,000	$1,000
Property Insurance			$32,115
Total	**$1,086**	**$138,680**	**$189,266**
Incremental Costs	$1,086	$137,594	$51,672
Total Incremental Costs			**$190,352**

a) Please explain the derivation of the $51,672.

Response:

a) 2021 Total of $189,266 subtract 2020 Incremental cost of $137,594.

$ 189,266 - $ 137,594 = $ 51,672

4 – VECC IRR – 26

4.0 -VECC -26

Reference: Exhibit 4, Appendix 2-JC

Typically, Appendix 2-JC (OM&A by programs) includes items such as Bad Debts, Collections, Information Technology, Tree Trimming, Locates, Property Insurance, Fleet management in addition to a breakdown of operations and maintenance costs into more detail - like metering, inspections etc. HHHI's Appendix 2-JC is essentially the same as Appendix 2-JA and does not include the costs of any individual programs or areas of activity in 2016 through 2021. Appendix 2-JB which shows annual changes in OM&A and Table 8 shows OM&A cost trends in much greater detail indicating that that HHHI does track OM&A costs at a more granular level.

a) Please provide a version of Appendix 2-JC which shows the OM&A by programs (like Table 8) or if such a chart is already provided in the evidence a reference to that table.

Response:

a) HHHI does not track OM&A by program level as requested. See Table VECC IRR – 17 for the OM&A by USofA Account from 2016 to 2021.

Table VECC IRR – 17 – OM&A by USofA

		Budget 2021 Test Year	Budget 2020 Bridge Year	Actual 2019	Actual 2018	Actual 2017	Actual 2016
	Distribution Expenses - Operation	-	-				
5005	Operation Supervision and Engineering	249,982	241,276	379,503	389,815	346,741	283,736
5010	Load Dispatching	-	-	-	-	-	-
5012	Station Buildings and Fixtures Expense	21,432	22,490	21,352	(1,320)	22,092	22,131
5015	Transformer Station Equipment - Operation Supplies and Expenses	17,830	17,600	1,086	-	-	-
5016	Distribution Station Equipment - Operation Labour	199,679	195,875	180,815	187,866	182,821	182,129
5017	Distribution Station Equipment - Operation Supplies and Expenses	44,651	43,533	43,143	21,334	34,989	52,735
5020	Overhead Distribution Lines and Feeders - Operation Labour	603,145	442,354	403,310	492,299	443,743	370,537
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	106,978	94,183	19,798	34,540	96,875	90,885
5035	Overhead Distribution Transformers- Operation	15,234	3,747	37,694	31,655	49,706	60,478
5040	Underground Distribution Lines and Feeders - Operation Labour	-	-	49,063	29,338	44,643	137,742
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	32,263	32,095	33,385	18,403	29,461	7,141
5060	Street Lighting and Signal System Expense	-	-	-	-	-	-
5065	Meter Expense	132,109	100,394	95,106	79,710	123,536	205,153
5085	Miscellaneous Distribution Expense	17,500	17,500	-	-	-	-
	Total Distribution Expenses - Operation	*1,440,803*	*1,211,047*	*1,264,254*	*1,283,640*	*1,374,606*	*1,412,667*
	Distribution Expenses - Maintenance						
5112	Maintenance of Transformer Station Equipment	4,000	4,000	-	-	-	-
5114	Maintenance of Distribution Station Equipment	99,000	82,050	7,532	11,965	7,616	7,210
5120	Maintenance of Poles, Towers and Fixtures	-	-	1,682	23,984	28,794	4,746
5125	Maintenance of Overhead Conductors and Devices	-	-	90	590	935	1,196
5135	Overhead Distribution Lines and Feeders - Right of Way	300,500	275,000	202,893	237,067	230,500	412,355
5150	Maintenance of Underground Conductors and Devices	54,500	54,500	93,440	43,801	14,888	16,957
5175	Maintenance of Meters	-	-	-	27	270	2,195
	Total Distribution Expenses - Maintenance	*458,000*	*415,550*	*305,637*	*317,433*	*283,003*	*444,659*
	Billing And Collecting						
5305	Supervision	148,413	144,692	139,769	138,076	129,762	197,065
5310	Meter Reading Expense	24,150	22,391	21,546	17,909	27,547	35,406
5315	Customer Billing	385,403	391,899	389,031	391,285	407,468	400,331
5320	Collecting	542,391	535,380	497,159	524,588	478,766	483,241
5325	Collecting- Cash Over and Short	-	-	-	-	167	(0)
5330	Collection Charges	7,500	6,800	8,149	6,783	4,671	6,097
5335	Bad Debt Expense	70,000	70,000	70,000	70,000	82,500	(24,507)
	Total Billing And Collecting	*1,177,856*	*1,171,162*	*1,125,654*	*1,148,642*	*1,130,882*	*1,097,634*
	Administr and Gen Expenses						
5605	Executive Salaries and Expenses	1,010,357	897,490	760,104	675,801	613,754	649,702
5610	Management Salaries and Expenses	545,715	530,749	520,769	517,025	490,349	470,246
5615	General Administrative Salaries and Expenses	1,055,826	838,434	929,944	863,607	859,978	599,729
5620	Office Supplies and Expenses	126,094	114,179	108,875	105,734	113,712	124,892
5630	Outside Services Employed	116,220	96,795	216,532	181,478	81,857	194,420
5635	Property Insurance	74,845	40,695	53,323	32,745	43,819	44,150
5640	Injuries and Damages	91,107	88,282	80,905	85,187	69,994	71,786
5645	Employee Pensions and Benefits	145,563	117,565	109,784	51,139	54,142	47,235
5655	Regulatory Expenses	172,200	98,814	130,481	145,658	114,951	130,040
5660	General Advertising Expenses	1,400	1,400	1,400	5,837	8,155	11,350
5665	Miscellaneous General Expenses	927,630	573,571	457,566	426,295	493,989	452,944
5675	Maintenance of General Plant	217,756	210,637	222,956	212,004	243,156	260,687
5680	Electrical Safety Authority Fees	-	-	-	-	-	-
	Total Adminstration & General Expenses	*4,484,712*	*3,608,611*	*3,592,639*	*3,302,510*	*3,187,857*	*3,057,180*

4 – VECC IRR – 27

4.0 -VECC -27

Reference: Exhibit 4, page 40

18 **Table 21 - PWU Annual Wage Increase**

Union Staff Annual Wages Increase

	Actual	Actual	Actual	Actual	Actual	Budget effective date	Budget effective date
	01-Apr-16	01-Apr-17	01-Apr-18	01-Apr-19	01-Oct-19	01-Apr-20	01-Apr-21
Annual Wages Increase	2.00%	2.00%	2.20%	1.30%	1.00%	2.00%	2.25%

a) What is the anticipated time frame for the union contract negotiations to resume?

b) It is unclear from the referenced table as to why 2019 increases were 1 to 1.3% whereas the 2020 and 2025 amounts are higher. Under the agreed extension of the current contract is there an agreement as to the wage increases for 2020 and 2021? If so what is that amount?

c) Do Non-Union/Management increases generally follow that for Union employees?

Response:

a) Union contract negotiations resumed October 19, 2020.

b) HHHI has agreed to the following wage increases following collective bargaining:

- April 1, 2020 1.2%
- November 1, 2020 1.2%
- April 1, 2021 1.2%
- November 1, 2021 1.2%

c) Generally speaking, Non-Union/Management increases generally follow that for Union employees.

4 – VECC IRR – 28

4.0 -VECC -28

Reference: Exhibit 4, Table 38 Shared Services

a) Please explain the large increase in services contracted from SouthWestern Energy Inc since 2016. What work is performed by this company?

b) What is the markup rate of this company?

Response:

a) As per page Exhibit 4, page 72, SouthWestern Energy Inc. provides civil and electrical contracting services to HHHI. These services are primarily for capital projects.

b) The percentage of mark-up for services relating to electrical contracting services is not public information and forms part of the proprietary information belonging to the respective non-regulated affiliate corporations.

4 – VECC IRR – 29

4.0 -VECC -29

Reference: Exhibit 4, Table 38 Shared Services

a) Please explain the large increase in services contracted from 2008949 Ontario. Specifically, was vegetation management previously done internally or by contractors other than this company?
b) Does this company do all or a portion of HHHI's vegetation management? If a portion please clarify as to proportion of work completed internally, by other contractors and by 2008949.
c) Does this company use its own vehicles for tree trimming and other vegetation management services?
d) Does this company (2008949) have a commercial name that can be identified by customers when it is working?
e) What is the markup rate of this company?

Response:

a) The increase in services contracted from 2008949 Ontario is for vegetation management. Vegetation management was previously contracted to another company.

b) Yes, this company is currently responsible for HHHI's vegetation management.

c) Yes, this company has its own vehicles.

d) Yes, this company is also known as Quality Tree Service.

e) The percentage of mark-up for services relating to electrical contracting services is not public information and forms part of the proprietary information belonging to the respective non-regulated affiliate corporations.

4 – VECC IRR – 30

4.0 -VECC -30

Reference: Exhibit 4, Table 38 Shared Services

a) Are all the amounts paid to Southwestern and 200849 included in the 2016 through 2019 actual OM&A costs as presented in Appendix 2-JA?

b) If some of these costs are capitalized please explain under what USOA accounts the capitalized amounts would be found and what those amounts were (and are estimated to be) in the 2016-2021 period.

c) What the amounts paid to date to date to these companies in 2020?

d) The 2021 application includes all the forecast costs of the Utility. What is HHHI forecast for the services that it expects SouthWestern Energy and 2008949 to undertake in 2021 and that it has included for rate recovery?

Response:

a) The amounts paid to 200849 Ontario Ltd. and SouthWestern Energy Inc. from 2016 to 2019 were recorded as an OM&A expense and capitalized with the OM&A portion included in Appendix 2-JA.

b) The costs that were capitalized were recorded under a job costing along with other costs related to that job. At the completion of the job, the total costs are then componentized and allocated to the various asset classes. HHHI does not track costs at such a granular level so as to provide the amount capitalized by vendor to each job and then to each USofA. Table VECC IRR - 17 presents the amount that was capitalized and expensed from 2016 to 2020.

Table VECC – 17 – Capitalized and Expensed Costs from 2016 to 2020

		2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 YTD Actual	2021 Test Year Budget
SouthWestern Energy Inc							
	Capital	916,517	1,693,018	1,963,910	1,536,833	519,172	730,910
	OM&A	28,773	3,784	38,896	96,171	107,753	53,500
	Total	**945,290**	**1,696,802**	**2,002,806**	**1,633,004**	**626,926**	**784,410**
2008949 Ontarion Ltd							
	Capital	66,150	31,937	288,378	134,738	21,633	-
	OM&A	13,050	7,609	7,767	136,903	238,795	300,000
	Total	**79,200**	**39,546**	**296,145**	**271,641**	**260,428**	**300,000**

c) Please see HHHI's response 4 – VECC IRR – 30 part b.

d) The 2021 application includes all forecast costs (Capital and OM&A) of the Utility. HHHI is not able to forecast the services it expects SouthWestern Energy Inc. and 2008949 Ontario Ltd to undertake in 2021 as there is no guarantee the respective affiliated companies will be successful to obtain the work.

4 – VECC IRR – 31

4.0 -VECC -31

Reference: Exhibit 4, Table 39

a) What are the actual amounts paid for EDA membership in 2016 through 2020 and the amount included in rates for 2021?

Response:

a) Please see Table VECC IRR – 18.

Table VECC IRR – 18 – EDA Membership Costs

Year	EDA Membership Fees
2016	$ 48,300.00
2017	$ 48,800.00
2018	$ 49,800.00
2019	$ 50,800.00
2020-Bridge Year	$ 51,800.00
2021-Test Year	**$ 52,300.00**

4 – VECC IRR – 32

4.0-VECC-32

Reference: Exhibit 4, Appendix 2-M, Regulatory Costs

a) What was the most recent annual assessment invoice cost (i.e. 2019 or 2020) from the OEB?

b) Please provide a table showing the forecast $280,000 one-time costs for this application in the categories: Legal, Consultants, Customer Engagement internal staff and Intervenors and show in the amounts spent to date on each category.

Response:

a) The most recent annual assessment invoice cost was $94,428 for 2020/2021.

b) Please see Table VECC IRR – 19 – Regulatory Costs for EB-2020-0026. HHHI would like to note that these are expenses received to date.

Table VECC IRR – 19 – Regulatory Cost for EB-2020-0026

Categories	Forecasted EB-2020-0026 Costs	Application Costs to Date
Expert Witness costs	4,617	8,730
Legal costs	140,704	-
Consultants' costs	24,090	35,865
Incremental operating expenses - staff resources	4,000	-
Incremental operating expenses - other resources allocated	3,850	-
Intervenor costs	49,083	-
OEB Section 30 Costs (application-related)	11,288	-
Customer Engagement	42,368	8,475
Total	**280,000**	**53,070**

4 – VECC IRR – 33

4.0-VECC-33

Reference: Exhibit 4, Section 4.7.1

a) Please provide the amount of LEAP funding provided to Links2Care in each year 2016 -2020.

b) Is HHHI provided a report on the LEAP funding dispersed in each year? If so please provide than amount for each year 2016- 2020 (or 2019).

c) We visited the Link2Care website for Halton related items but were unable to find any link to LEAP assistance (though we did find links to phone assurance programs). Is HHHI aware of how Links2Care communicates the availability of LEAP assistance?

Response:

a) See Table VECC IRR – 20.

b) See Table VECC IRR - 20.

Table VECC IRR – 20 – LEAP Funding for Links2Care (2016-2019)

Year	LEAP funding provided	LEAP funds dispersed	Admin Fee (15% allowable)
2016	$ 10,346	$ 8,406	$ 1,940
2017	$ 11,945	$ 10,153	$ 1,792
2018	$ 11,945	$ 11,945	$ -
2019	$ 11,945	$ 10,387	$ 1,558

c) As the Town of Halton Hills is still considered a small community, much of the communication is done over the phone and in person (pre-COVID). HHHI is constantly in contact with Links2Care and regularly refers customers to their services.

Links2Care uses the first contact with clients / customers to assess the needs of the person / family and recommend the assistance programs that provide the person/ family with the most benefit. These programs include Regional assistance, disability insurance, employment insurance in addition to LEAP.

4 – VECC IRR – 34

4.0 -VECC -34

Reference: **Exhibit 4, page 117**
LRAMVA Model, Tab 5

a) Have the 3,287,636 kWh of savings in 2018 from 2018 programs been verified by the IESO or any other third party?

Response:

a) Savings equal to 3,287,636 kWh for 2018 have not been verified by the IESO or a third party. These savings represent the total 2018 Unverified results from the IESO's April 2019 Participation and Cost Report.

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

5 – VECC IRR – 35

5.0-VECC-35

Reference: Exhibit 5, Section 5.5.4, pages 14-5

a) Please reconcile the Interest Swap #1 amount of $23.0 million with the amount of $22,080,143 shown in Appendix 2-OB.

Response:

a) Please refer to amortization Table in Exhibit 5, page 32.

5 – VECC IRR – 36

5.0-VECC-36

Reference: Exhibit 5, Section 5.5.4, pages 14-5

The Table below is extracted from the ongoing proceeding of Niagara Peninsula, EB-2020-0040.

Source: Niagara Peninsula Energy Ince Appendix 2OB EB-2020-0040 Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]
1	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-15	5	$ -	0.0267
2	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-17	10	$ 10,000,000	0.0281
3	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-18	10	$ 10,000,000	0.03671
5	Term Loan payable	Scotiabank	Third-Party	Fixed Rate	6-Nov-19	5	$ 10,000,000	0.02698
6	Term Loan payable	Meridian Credit Union	Third-Party	Fixed Rate	13-Sep-16	10	$ 20,000,000	0.026
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	1-Aug-19	10	$ 25,600,000	0.0276
8	Term Loan payable	Scotiabank	Third-Party	Fixed Rate	6-Nov-19	5	$ 7,234,630	0.02698
9								
Total							$ 82,834,630	2.84%

a) The most recent debt amounts negotiated in the summer and fall of 2019 by that Utility show an average interest rate of around 2.7%. HHHI has negotiated a 30-year swap rate at 4.095%. Please explain why HHI believe a longer term, potentially at a higher rate of interest, was preferrable to a shorter term at lower rates.

b) Please explain how HHHI ensured that the 4.095% was the best rate it could receive in the market at the time of its negotiation.

Response:

a) Referring to EB-2015-0074 the OEB approved Cost of Debt Instruments for HHHI was 2.809%. During the subsequent years and specifically during 2018 interest rates had been very volatile and this was expected to continue. The year 2018 was a year of tremendous volatility, bond yields alone had an almost 1.00% swing, with the fall being one of the bumpiest times of the year. HHHI suffered as a result of this interest rate volatility.

HHHI's strategic objective was to hedge interest rate exposure on Long-Term Debt, by establishing a fixed interest rate 'today' for 30 years. Alternatively, a conventional loan renewing in shorter frequencies has an inherent interest rate risk, especially during periods of rising interest rates. HHHI's preferred risk management approach is to match the interest rate exposure to corresponding assets and not be exposed to rate risk at each loan renewal, providing interest rate stability for HHHI and its customers.

On January 15, 2019, HHHI forward booked a 30-year interest rate swap funding on September 3, 2019 at an all-in rate of 4.095%. A comparable conventional loan on a 10-year term, 30-year amortization on the same booking date and funding date would have been approximately 3.95% for HHHI. HHHI acknowledges there is no way to know ex-ante which combination of interest rate tenors would produce the lowest cost over the life of the amortization schedule. HHHI's priority is on interest rate stability and consistency for our customers.

Comparing HHHI's January 2019 rate to Niagara Peninsula's August 2019 rate is not a valid comparison; as an interest rate booked in January for a loan funding in September cannot be compared to a loan booked at spot in August. The economic conditions changed significantly during that short period of time.

Typically in this sector, when an upcoming funding is known both in amount and timing, it's forward locked to take the interest rate risk off the table. This creates interest rate certainty. This is the "prudent" or "conservative" thing to do, otherwise the utility is sitting on the exposure. This is especially true following a recent trend that was forecasted to continue. HHHI also understand this risk management approach is in-line with many of our peers.

HHHI has now successfully mitigated interest rate exposure on the Long-term Debt, providing interest rate stability in this Application and for future applications over the next 30 years, all of which will benefit HHHI's Customers in the long term. HHHI is comfortable with the interest rate booked given the market conditions in January 2019.

b) Based on HHHI's strategic objective to hedge interest rates for a 30 year period, the interest rate swap mitigates HHHI's risk on the floating-rate debt liability as it is matched to the building and commissioning of a long service life asset (a.k.a. MTS#1). The year 2018 was a year of tremendous volatility, bond yields alone had an almost 1.00% swing, with the fall being one of the bumpiest times of the year. This volatility was expected to continue into 2019. On January 15, 2019, HHHI forward booked a 30-year interest rate swap funding on September 3, 2019 at an all-in rate of 4.095%. A comparable conventional loan on a 10-year term, 30-year amortization on the same booking date and funding date would have been approximately 3.95% for HHHI. HHHI is comfortable with the rate booked given the market conditions in January 2019.

5 – VECC IRR – 37

5.0-VECC-37

Reference: Exhibit 5, Section 5.5.4, page 12

a) Please complete Appendix 2-OB (Exhibit 5, page 12) to show the start date and term of all of the debt instruments.

b) Please reconcile the total amounts shown in Appendix 2-OB (113,597,337) with the amounts shown at page 12 (69,561,039) and the difference in interest rates (2.13% and 3.476%)

Response:

a) Please see HHHI's response 5 – SEC IRR – 39.

b) Please note, in Appendix 2-OB Cells 'CB39' and 'CC39' are protected and HHHI is unable to update. The amounts shown in Exhibit 5, page 12 are correct for the 2021 Test Year as at December 31, 2021.

5 – VECC IRR – 38

5.0-VECC-38

Reference: Exhibit 5, Section 5.5.4, pages 12

a) Please reconcile amounts shown for long-term debt in the RRWF (Niagara_Peninsula_Energy_Inc_Appl_2020_Rev_Reqt_Work_Form_20200818.XLSM) with the amounts shown in Appendix 2-OB (page 12).

Response:

a) HHHI is unable to reconcile the amounts from Appendix 2-OB (page 12) with the Niagara Peninsula Energy Inc. RRWF.

6.0 CALCULATION OF REVENUE DEFICIENCY/SURPLUS (EXHIBIT 6)

6 – VECC IRR – 39

6.0-VECC-39

Reference: Exhibit 6, Table 10, page 15

a) HHHI projects a revenue deficiency of $5,422,387 and a gross deficiency of $7,377,397. What amount of these deficiencies are attributable to the new HHHI owned transfer station? Please show the calculation for this attribution.

Response:

a) The revenue deficiency with the transformer station and the revenue deficiency without the transformer station are shown in Table VECC IRR – 21.

Table VECC IRR – 21 – Revenue Deficiency Comparison

	With Transformer Station			Without Transformer Station	
Particulars	**At Current Approved Rates**	**At Proposed Rates**		**At Current Approved Rates**	**At Proposed Rates**
Revenue Deficiency from Below		7,377,397			3,369,657
Distribution Revenue	10,330,095	8,375,085		10,330,095	10,330,095
Other Operating Revenue Offsets - net	1,293,382	1,293,382		1,293,382	1,293,382
Total Revenue	**11,623,478**	**17,045,865**		**11,623,478**	**14,993,135**
Operating Expenses	11,349,150	11,349,150		10,510,036	10,510,036
Deemed Interest Expense	2,143,902	2,143,902		1,687,170	1,687,170
Total Cost and Expenses	13,493,052	13,493,052		12,197,205	12,197,205
Utility Income Before Income Taxes	(1,869,574)	3,552,813		(573,727)	2,795,930
Tax Adjustments to Accounting Income per 2013 PILs model	(6,080,230)	(6,080,230)		(6,730,078)	(6,730,078)
Taxable Income	(7,949,803)	(2,527,416)		(7,303,805)	(3,934,148)
Income Tax Rate	26.50%	26.50%		26.50%	26.50%
Income Tax on Taxable Income	-	-		-	-
Income Tax Credits	-	-		-	
Utility Net Income	**(1,869,574)**	**3,552,813**		**(573,727)**	**2,795,930**
Utility Rate Base	**104,249,216**	**104,249,216**		**82,040,186**	**82,040,186**
Deemed Equity Portion of Rate Base	41,699,686	41,699,686		32,816,074	32,816,074
Income/(Equity Portion of Rate Base)	(4.48)%	8.52%		(1.75)%	8.52%
Target Return - Equity on Rate Base	8.52%	8.52%		8.52%	8.52%
Deficiency/Sufficiency in Return on Equity	(13.00)%	0.00%		(10.27)%	0.00%
Indicated Rate of Return	0.26%	5.46%		1.36%	5.46%
Requested Rate of Return on Rate Base	5.46%	5.46%		5.46%	5.46%
Deficiency/Sufficiency in Rate of Return	(5.20)%	0.00%		(4.10)%	0.00%
Target Return on Equity	3,552,813	3,552,813		2,795,930	2,795,930
Revenue Deficiency/(Sufficiency)	5,422,387	-		3,369,657	-
Gross Revenue Deficiency/(Sufficiency)	**7,377,397**			**4,584,567**	

7.0 COST ALLOCATION (EXHIBIT 7)

7 – VECC IRR – 40

7.0 – VECC –40

Reference: **Exhibit 7, pages 5-6**
Cost Allocation Model, Tab I4

Preamble: The Application states: "*A weighting factor was determined by assigning the Residential customer class a factor of 1.0, as required, and determining the relative weights of the rest of the classes. As per Table 7-1, HHHI applied a weighting factor of 1.0 for Residential. For General Service less than 50 kW, General Service 50 to 999 kW and General Service 1,000 to 4,999 kW have a factor of 0.0 since any costs are recovered fully through capital contributions received from those customers.*"

a) With respect to Tab I4, please confirm that the asset values set out in Column C are the gross asset values prior to the removal of capital contributions.

b) Tab I4 shows $120,512 in contributed capital that is attributed to Services (Acct. 1855). Does this amount represent the actual contributed capital paid by customers for their Services or is it simply based on an allocation of the total contributed capital to assets?

   i. If based on an "allocation", please provide the 2021 cumulative value for the contributed capital HHI is forecast to receive as of 2021 for customers' Services.

c) Are the Services assets used to supply GS customers owned by HHI or the customers themselves?

d) If some or all of the Services assets used to supply GS customers are owned by HHHI and HHHI is responsible for the ongoing OM&A costs related to these assets then:

   i. In the Cost Allocation Model, are there OM&A costs attributed to Services assets that are subsequently allocated to customer classes?

   ii. If yes, please indicate where in the CA model this occurs and if the GS classes are attributed a portion OM&A costs for these assets.

   iii. If the GS classes are not attributed a portion of the OM&A associated with the Services assets, what is HHHI's estimate as to the annual OM&A cost for 2021 related to the Service assets used to supply each of these customer classes?

e) Do the Streetlight, Sentinel or USL customers have Services assets that are owned and/or maintained by HHHI? If yes, please explain why the Services weighting factors for these classes are all zero.

Response:

a) Confirmed.

b) The $120,512 is based on an allocation of the total contributed capital to assets. $1,135,176 of contributed capital is forecasted to be received in 2021.

c) Assets recorded in Account 1855 are owned by HHHI.

d) HHHI is not able to answer this question as HHHI does not track OM&A to that level of granularity.

e) HHHI does not own any Streetlight, Sentinel or Unmetered Scattered Load service assets.

7 – VECC IRR – 41

7.0 – VECC –41

Reference: Exhibit 7, page 7

a) Please explain why more up to date costs for installing different types of meters were not determined and used in the Cost Allocation Model.

Response:

a) HHHI does not anticipate the current costs to be materially different than what is used in the Cost Allocation Model.

7 – VECC IRR – 42

7.0 – VECC –42

Reference: **Exhibit 7, page 8**
Cost Allocation Model, Tab I6.2

a) Please confirm that each Streetlighting device is separately connected to HHHI's distribution system such that the number of devices equals the number of connections. If not confirmed, please explain the relationship and indicate the necessary revisions to Tab I6.2.

Response:

a) HHHI does not have enough information at this time to confirm this. For the purpose of the cost allocation mode, HHHI assumes that each device is connected separately.

7 – VECC IRR – 43

7.0 – VECC –43

Reference: Exhibit 7, pages 12-14
Cost Allocation Model, Tab 01

a) Please explain more fully how/why setting the Revenue to Cost Ratio for Residential at 105.67% would cause a significant rate increase for that class as suggested on page 14.

Response:

a) If HHHI, were to keep the Revenue to Cost Ratio for Residential at 105.67% and move the other customer classes according to Board policy, Residential customers would have a distribution rate increase of 52.5%.

8.0 RATE DESIGN (EXHIBIT 8)

8 – VECC IRR – 44

8.0 –VECC - 44

Reference: Exhibit 8, page 13

a) For the GS<50 class where the Minimum System with PLCC Adjustment (Ceiling Fixed Charge) from Cost Allocation from is $24.59, please reconcile the proposal to increase the fixed charge from $29.39 to $48.43 with the Board's Filing Guidelines , Chapter 2, page 54 which state:

> "*If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling for any non- residential class*." (Emphasis added)

Response:

a) HHHI will update the fixed change for General Service less than 50 kW to $29.39 as part of Settlement.

8 – VECC IRR – 45

8.0 –VECC - 45

Reference: Exhibit 8, pages 16-17 and Appendix 8-3
Cost Allocation Model /RRWF, Rate Design Tab

a) Please indicate where/how the monthly reserve capacity billing quantity has been included in the cost allocation model revenue and the determination of total revenues at the proposed rates.
b) Will the Capacity Reserve Charge be applied in all months, including those when the customer's generation is not operating for part of the month and standby capacity is required?
c) The proposed tariffs for 2021 (Appendix 8-3) do not include the Standby Charge. Please provide draft of the proposed Standby Charge tariff sheet including the wording that will be used to describe how the billing determinants will be calculated and the rate applied.
d) Will the load displacement customer's load impact the ST charges levied on HHHI by HONI?
    i. If yes, since HON's ST charges are based on gross load billing, does HHHI proposed to levy LV charges on a "gross load" basis?

Response:

a) The monthly reserve capacity billing quantity has not been included in the cost allocation model revenue.

b) Please see HHHI's response 4 - Staff IRR – 76.

c) Please see HHHI's response 4 – Staff IRR – 76.

d) Please see HHHI's response 4 – Staff IRR – 76.

8 – VECC IRR – 46

8.0 –VECC – 46

Reference: **Exhibit 8, page 21 and Appendix 8-3**

Preamble: The Application states: "For the purposes of providing a complete 2021 Proposed Tariff of Rates and Charges, HHHI has utilized the current 2020 Retailer Service Charges as issued by the OEB Decision and Rate Order dated November 28, 2019 in proceeding EB-2019-0280 and shown in HHI has forecasted its retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement".

a) What is the basis for the 2021 Retail Service Charges (Exhibit 8, page 81)?

Response:

a) The 2021 Retail Service Charges shown in the 2021 Proposed Tariff of Rates and Charges is a place holder. The OEB will issue the updated Retail Service Charges. HHHI assumed a 2.0% increase.

8 – VECC IRR – 47

8.0 –VECC – 47

Reference: **Exhibit 8, page 27 / Exhibit 3, page 51**

Preamble: The Application states: "HHHI understands and accepts that the Wireline Pole Attachment Charges will be updated with the 2021 rates once approved by the Board. For the purposes of providing a complete 2021 Proposed Tariff of Rates and Charges, HHHI has utilized the current 2020 Wireline Pole Attachment Charges as provided in the cover letter issued by the OEB in its Decision and Rate Order dated November 28, 2019 in proceeding EB-2019-0280 in the amount of $44.50 per attacher per year per pole."

a) What was the pole attachment charge used to forecast the 2021 Pole Rental revenue – per Exhibit 3, page 51?

Response:

a) Please refer to Exhibit 8, page 27 "HHHI has utilized the current 2020 Wireline Pole Attachment Charges as provided in the cover letter issued by the OEB in its Decision and Rate Order dated November 28, 2019 in proceeding EB-2019-0280 in the amount of $44.50 per attachment per year per pole."

8 – VECC IRR – 48

8.0 –VECC – 48

Reference: Exhibit 8, page 30

a) It is noted that in 2019 the charges from HONI increase by over 30% despite a decrease in the billing demand. Please provide further details on the basis for the 2018 and 2019 charges and the reasons for the significant increase.
b) It is noted that in 2020 the charges from HONI increased again by more than 30%. Please provide further details on the basis for the forecast 2020 charges so as to explain the reasons for the significant increase.

Response:

a) As explained in Exhibit 8, page 30, HONI charges increased substantially from 2018 to rates effective July 1, 2019. In particular, the fixed rates increased from $492.55 per month per feeder in 2018 to $559.54 per month per feeder in 2019. Additionally, volumetric rates increased from $1.2052 /kW in 2018 to $2.34/kW in 2019. HHHI would like to note that the increase in rates was only in effect for six (6) of the months in 2019.

b) As explained in part a, the 2019 HONI charges reflect the rate increase effective July 1, 2019 (6 months in 2019). Effective January 1, 2020, HONI charges increased again. The combined increase (July 1, 2019 and January 1, 2020) had a significant impact on the total charges.

9.0 DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9 – VECC IRR – 49

9.0 –VECC -49

Reference: Exhibit 9, page 23

"On September 25, 2017, HHHI made an application to the OEB (EB-2017-0215) requesting the approval of a deferral and variance account to record an adjustment to the revenue requirement in the amount of $330,259 per year"

Table 11 - Depreciation Adjustment Forecasted Variance Calculations

Depreciation Adjustment	$
Annual Depreciation not included in 2016 Rates	330,264
Monthly Depreciation Adjustment Amount	27,522
Forecasted Transactions from January 1, 2020 to April 30, 2021 (16 months)	440,352

a) EB-2017-0215 refers to an application by Natural Resource Gas Limited. Please provide the correct reference for this application. Please confirm the proceeding in question and the correct reference is EB-2017-0045.

b) The derivation of the $27,522 in Table 11 is unclear to us, please clarify.

Response:

a) HHHI confirms that the correct reference is EB-2017-0045.

b) In EB-2017-0045 Decision and Rate Order, the Ontario Energy Board approved the amount of $330,259 to be recorded annually in the deferral account until the next cost of service. The $27,522 is the monthly amount (annual recorded amount divided by 12 months).