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.

OEB STAFF INTERROGATORIES AND RESPONSES

*Responses to interrogatories, including supporting documentation, must not include personal information unless filed in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

Exhibit 1- Administration

1 - Staff IRR - 1

1-Staff-1
Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2021 Electricity Distributor Rate Applications webpage.

Response:

The updated models have been filed separately through RESS and include:

- Halton_IRR_4-Staff-58b_LRAMVA_20201125
- Halton_IRR_Cost_Allocation_Model_20201125
- Halton_IRR_Test_year_Income_Tax_PILs_20201125
- Halton_IRR_Rev_Reqt_Workform_20201125

1 - Staff IRR - 2

1-Staff-2
Letters of Comment

Following publication of the Notice of Application, the OEB received 25 letters of comment. Section 2.1.7 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

HHHI will have responded to all customers by November 30, 2020. The responses will all be filed on the record on or before November 30, 2020.

Customer Engagement

1 - Staff IRR - 3

1-Staff-3
Ref: Exhibit 1/Section 1.7

Preamble:

Through the customer engagement activities undertaken in support of this Application, HHHI identified key themes/feedback from customers:

1. Reliability and reasonable rates
2. Customers are strongly in favour of a proactive replacement strategy rather than a run-to-failure approach
3. Reducing power outages
4. Accommodating renewable energy resources and addressing climate change

Question(s):

a) Did HHHI make any changes to its draft Operating, Maintenance and Administration (OM&A) and capital budgets after the review of customers' feedback from the customer engagement activities?

b) HHHI identified a few programs that are aimed at reducing power outages, including pole replacement projects, tree trimming program, and SCADA integration of automated switches.

    i. Please confirm the proposed capital expenditures on the pole replacement program is $624,199 for the 2021 test year.
    ii. Please confirm the proposed capital expenditures on the automated switches and SCADA integration program is $231,194 for the 2021 test year.
    iii. Please specify the budget for the tree trimming program for the 2021 test year. OEB staff notes that HHHI purchases tree trimming services from its affiliate company. Please clarify whether HHHI treats the tree trimming expense as an OM&A cost or as an offsetting item in other operating revenue.
    iv. Based on HHHI's historical power outage data by cause (Exhibit 2, Distribution System Plan, section 2.3.1.3.4, Table 12), please explain what improvements HHHI expects to achieve in the performance of system reliability in the next five years with the execution of these projects.

c) HHHI noted that 15% of survey respondents indicated that they were considering installing electric vehicle (EV) charging stations within the next five years, and 31.7% of poll respondents indicated that they were considering installing battery storage to provide back-up power supply in the next five years. HHHI is also committed to assist the Town of

Halton Hills by providing guidance on the strategic placement of EV charging stations within the distribution system.

i. Please specify how many customers that "15% of survey respondents" and "31.7% of poll respondents" represent.
ii. Please explain what actions HHHI plans to undertake to facilitate customers to install EV charging stations and/or battery storage.
iii. Please clarify whether HHHI included any capital expenditures and/or OM&A costs associated with activities facilitating customers' installation of EV charging stations and/or battery storage. If so, please specify the proposed capital expenditures and/or OM&A costs.
iv. HHHI stated that it "will review opportunities to invest in EV charging for the community". Does HHHI plan to own and operate any EV charging station? If so, please discuss the policy basis that permits the ownership and/or operation of an EV charging station as a distribution activity.
v. Please explain what actions HHHI plans to undertake to assist the Town of Halton Hills on the strategic placement of EV charging stations within the distribution system.
vi. Please clarify whether HHHI included any capital expenditures and/or OM&A costs related to assisting the Town of Halton Hills with the installation of EV charging stations within the distribution system. If so, please specify the proposed capital expenditures and/or OM&A costs.

d) HHHI noted that the online customer engagement platform provided meaningful results at a fraction of the cost of conventional customer engagement methods. How much was spent on the customer engagement platform compared to what would have been spent in a conventional approach?

Response:

a) Customer engagement was considered and evaluated in each project. Details of the customer engagement impacts can be found in the individual project sheets. As stated in the DSP, customers showed a strong preference for a proactive replacement instead of run to failure. Our System Renewal programs, in particular, porcelain insulator replacement, defective transformer replacement, pole replacements and poletrans replacement programs directly address this preference.

As well, voltage conversion projects improve reliability, support grid modernization, support for DERs and provide increased system hardening to address climate change.

Some specific projects directly affected by customer engagement include:

Pole replacements – In HHHI's previous asset management plan, SP14-03, HHHI recognized that there was a backlog of wooden utility poles that were beyond their useful life. As identified in the 2016-2020 Distribution System Plan, HHHI undertook a proactive approach to replacements aimed at reducing the backlog of poles beyond their useful service life. Through the period of that plan, significant headway was made to reduce the backlog of old or poor condition poles. As a result, HHHI has significantly reduced the pole replacement budget in the current DSP to address customer preference for reasonable rates. Keeping in mind the balance of low cost electricity service and a reliable supply of electricity, HHHI has adjusted the pole replacement budget moderately upwards each year by approximately the rate of inflation to prevent a new backlog of poor condition assets from amassing. This approach addresses customer preference for proactive replacement of aging assets while balancing customer preference for affordable cost of electricity.

Porcelain insulators - Replacement of porcelain insulators with polymer insulators is supported by customer engagement as customers have indicated HHHI should proactively replace equipment to improve reliability.

SCADA switch/device integration - Customers have expressed interest in HHHI creating a more modern grid, including increasing automation to reduce the length of power outages. As such, HHHI will be focusing on continuing to activate automated switches within the distribution system.

Defective transformer replacements – Customers have shown strong support for proactive replacement to improve reliability.

Technical Service Layouts - 31.7% of respondents to the poll on battery storage indicated interest in installing battery storage to provide back-up power supply to their home or business in the next five (5) years. Through the Technical Service Layout process, we are able to accommodate these types of installations.

b) Reducing power outages
   i. With reference to Exhibit 2 page 232, HHHI confirms the proposed pole replacement capital expenditure program for the 2021 test year is $624,199.

   ii. With reference to Exhibit 2 page 232, HHHI confirms the proposed automated switches and SCADA integration capital expenditure program for the 2021 test year is $231,194.

   iii. The 2021 test year vegetation management budget is $300,000. HHHI treats the vegetation management expenses as OM&A.

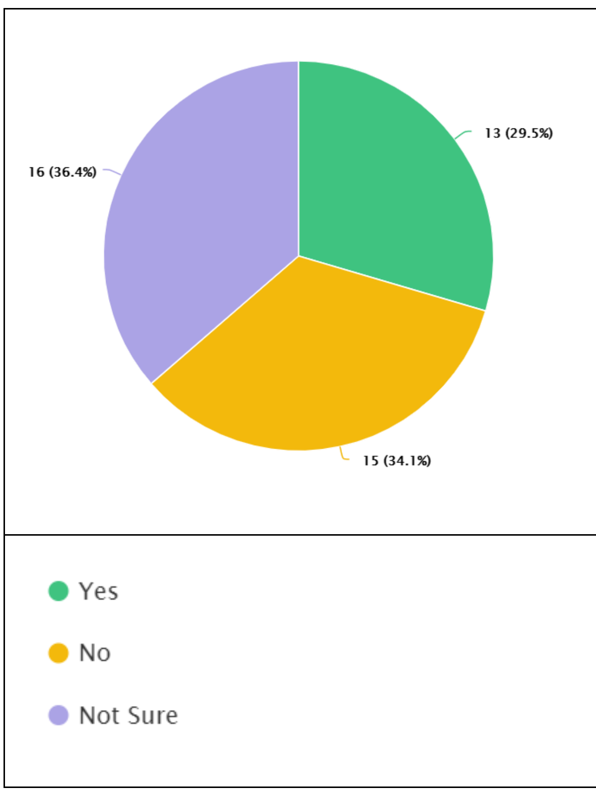
iv. Through completing system reliability improvement projects, HHHI is primarily targeting Tree Contact and Defective Equipment related power outages. While these projects certainly help reduce outages in these categories, they cannot eliminate them completely. Therefore, it is difficult to quantify an exact change in reliability statistics.

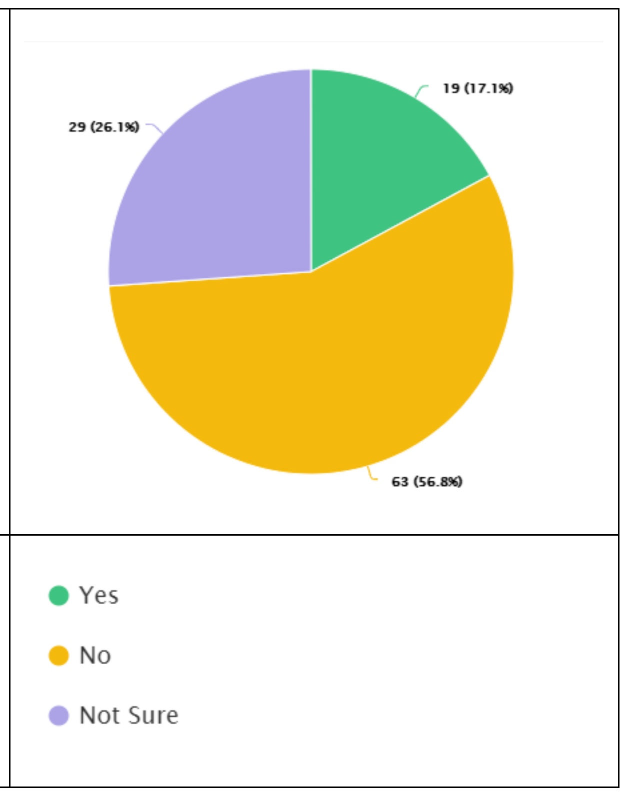
c) Electric vehicles

i. To clarify, customer polls specific to electric vehicle charging and battery storage were created separate from the formal surveys. Forty-one (41) customers responded to the battery storage poll. Thirteen (13) indicated that they were considering installing battery backup.

One hundred four (104) customers responded to the electric vehicle poll. Of those, sixteen (16) (or 15.4%) indicated that they were considering installing an EV charging station.

Do you plan on installing battery storage to provide back-up power supply to your home or business in the next 5 years?	**Do you plan on installing an Electric Vehicle charging station in your home in the next 5 years?**





ii. At this time, HHHI does not foresee any system capacity constraints related to EV charging or battery storage installation. HHHI works with customers looking to install such equipment to ensure their services are appropriately sized to handle the equipment. The feeder study planned through the Climate Change Plan will assist in identifying future system constraints or power quality concerns with the proliferation of EVs.

iii. Aside from the projects identified in collaboration with the Town of Halton Hills through the HHHI Climate Change Plan, HHHI does not have any specific projects targeting installation of EV charging stations or battery storage. These projects would be considered part of the Technical Service Layouts project under System Access. These projects are customer driven and would be handled individually as requests are received. HHHI's policy is beneficiary pays, thus, any capital costs would be borne by the customer. Additionally, HHHI provides maintenance to the demarcation point and as most EV charging stations and battery storage would be behind the meter, HHHI would not incur OM&A expenses.

iv. There is no current policy in place that permits the ownership and/or operation of an EV charging station. HHHI would adapt as necessary should a policy be introduced.

v. As part of its 2021-2025 strategic plan, HHHI created a Climate Change plan. HHHI will work with the Town of Halton Hills Low-Carbon Mobility subcommittee to evaluate locations for public charging. HHHI will provide funds for in-kind services to assist with the installation of these charging facilities as appropriate.

vi. In the 2021 OM&A budget, HHHI's Climate Change plan is $279,700. Of that, $66,700 has been allocated towards supporting the Town's low-carbon mobility strategy. HHHI will provide funds for in-kind services to assist with the installation of these charging facilities as appropriate.

d) The total cost for the customer engagement platform was $7,500 before HST. All content was created in house. Quotes for conventional customer engagement activities ranged from $58,805 to $112,400.

Treatment of COVID

1 - Staff IRR - 4

1-Staff-4
Ref: Exhibit 1/pp.22-23

Preamble:

When discussing the impact of the COVID outbreak, HHHI stated that the situation is dynamic and the ultimate duration and magnitude of the impact on the economy and HHHI's business are not known at the time of filing the Application.

Question(s):

a) Please clarify whether HHHI has included any impacts of the COVID emergency in its proposed 2020 and 2021 OM&A. If so, please specify the impacts.

b) Please clarify whether HHHI has included any impacts of the COVID emergency in its proposed 2020 and 2021 capital expenditures. If so, please specify the impacts.

c) OEB staff notes that HHHI has reported entries to the COVID-19 Account established by the OEB as of July 31, 2020 (Lost Revenues and Other Costs).[1]

   i. Please explain the types of costs/lost revenues associated with the amounts that HHHI has recorded in each sub-account.
   ii. Please discuss any other types of costs/lost revenues/savings that HHHI anticipates to record in the sub-accounts.

d) Please explain the interplay between the COVID adjustment made in the load forecast and the impacts of COVID emergency that will be dealt with by way of the COVID-19 Account (i.e. Account 1509 – Impacts Arising from the COVID-19 Emergency, Sub-Account Lost Revenues).

Response:

a) HHHI has not included any impacts of the COVID emergency in it proposed 2020 and 2021 OM&A.

b) HHHI has not included any impacts of the COVID emergency in it proposed 2020 and 2021 capital expenditures.

c) COVID-19 account
   i. HHHI is recording in Account 1509, Sub-accounts the following:

[1] COVID-19 Account Balances Reported by Electricity Utilities as of July 31, 2020. September 24, 2020.

- Costs associated with Billing System Changes relating to programing requirements to implement Customer Optionality.
- Lost Revenue resulting from forgone interest charges on overdue customer accounts, waived to July 21, 2020.
- Incremental OM&A costs actually incurred relating to COVID-19 including protective personal equipment (PPE) and other protective measures required to protect employees and customers.
- Incremental Bad Debt Expense.
- Forgone revenues from Postponing May 1st 2020 Rate Implementation to July 31, 2020.

ii. The COVID-19 situation is dynamic and the ultimate duration and magnitude of the impact on our business is not known. At this time, HHHI is unable to anticipate any other types of costs/lost revenues/savings.

d) There is no interplay between the COVID-19 adjustment made in the load forecast and the impacts of COVID-19 emergency account 1509.

Productivity

1 - Staff IRR- 5

1-Staff-5
Ref: Exhibit 1/Appendix 1-1: 2020 Corporate Business Plan/page 6

Preamble:

HHHI noted that it implemented an innovation tracking initiative at the department level in 2018 and there have been 162 innovation ideas created by staff. Innovation ideas have created $222,000 in cost savings and 2300 hours in productivity improvements.

Question(s):

a) Please provide a list of existing productivity initiatives that are currently in place for the 2016-2020 rate period.

b) Please identify any new productivity initiatives that are planned to be implemented for the 2021-2025 rate period.

c) Please specify activities/initiatives associated with the $222,000 cost savings and the 2300 hours productivity improvements.

d) Please provide a breakdown of cost savings for each of the activities/initiatives.

e) Please clarify whether the $222,000 represents an annual saving amount or cumulative savings over a few years.

f) Please clarify if any of the savings have been reflected in the proposed 2021 OM&A.
g) Please clarify if any of the savings have been reflected in the proposed 2021 capital expenditures.

Response:

a) Attachment Halton_Att_1-Staff-5a_Innovation_20201125 provides a list of the completed and in progress innovations to the end of 2019. The innovation initiative is as much focused on staff engagement as it is on cost savings or productivity improvements. Many of the ideas relate to improved customer service or internal communications, time savings or improved process. Many of the ideas do not have a specific dollar or hour savings attached to them but HHHI continues to encourage staff to bring forward their ideas in support of the concept of 'relentless incrementalism' where small improvements add up to greater change.

   The spreadsheet provided does not include ideas which were not implemented.

b) At this point in time, it is too early to project what initiatives may be in place in the 2021-2025 time period. As well, the ongoing COVID-19 situation is dynamic and the ultimate impacts on business are not known at this time.

c) Please see HHHI's response 1 – Staff IRR - 5 part a.

d) Please see HHHI's response 1 – Staff IRR - 5 part a.

e) The bulk of the savings identified are Avoided Costs, thereby reducing the need for further budget increases. The hour savings are productivity improvements that allow HHHI to continue to provide electricity distribution excellence without needing further increases in head count.

f) No. The bulk of the savings identified are Avoided Costs, thereby reducing the need for further budget increases. The hour savings are productivity improvements that allow HHHI to continue to provide electricity distribution excellence without needing further increases in head count.

g) No. The bulk of the savings identified are Avoided Costs, thereby reducing the need for further budget increases. The hour savings are productivity improvements that allow HHHI to continue to provide electricity distribution excellence without needing further increases in head count.

Exhibit 2 – Rate Base and Distribution System Plan

The New Municipal Transformer Station

2 - Staff IRR - 6

2-Staff-6
Ref: Exhibit 2/Section 2.3.6 & 2.5.6

Preamble:

The OEB approved Incremental Capital Module (ICM) funding of $23,476,441 for a new municipal transformer station (MTS) to serve future growth in HHHI's 2019 rate application.[2] In this Application, HHHI reported actual cost of $24,475,012 for this new MTS and requested to recover the additional cost through rate riders. HHHI provides a summary of additional costs in the table below.

Cost Category	Amount
Commissioning Costs	$342,387
Capitalization of interest, loan, property tax & legal	$179,622
SCADA programming, operating directives	$242,177
Equipment	$18,680
Labour	$153,364
Materials	$68,862
Land	$(6,521)
Total Costs since ICM	**$998,571**

Question(s):

a) Please specify the originally planned target in-service date filed in the 2019 rate application and the actual in-service date for the new MTS.

b) Please explain why the additional costs were not anticipated at the time of filing the ICM request.

c) Please explain what actions HHHI has taken to manage the actual costs as close to the OEB-approved budget as possible.

d) OEB staff notes the table below that provides the capital cost for the new MTS filed in HHHI's 2019 ICM application.[3] Please confirm the proposed ICM budget did not include contingency.

[2] EB-2018-0328
[3] EB-2018-0328, ICM Application, December 3, 2018, page 19.

Table 7 - TS Capital Cost Categories

Cost Category	Capital Cost	Amortization Expense	Capital Cost Allowance (CCA)		
			Class	Rate	Amount
TS Switchgear - Gas, Transformer	6,789,816	196,505	47	8%	543,185
Substation Equipment, U/G Cables, Meters, Capital Contribution	9,060,154	243,061	47	8%	724,812
Duct & Civil, Building	6,408,952	153,855	47	8%	512,716
SCADA & DC System	230,519	15,368	45	45%	103,734
Land	987,000	-	n/a	n/a	-
Total Costs	**23,476,441**	**608,789**			**1,884,447**

e) Please explain what "additional commissioning activities" were required that resulted in an additional cost of $342,387.

f) OEB staff notes that the budgeted costs for SCADA & DC System was $230,519 as proposed in the ICM application. The additional cost for SCADA programming is $242,177. Please explain why an increase of 105% in the spending of the SCADA system is reasonable.

g) Please confirm HHHI has spent about 92%[4] of the budget at the end of 2018 when the ICM application was filed.

Response:

a) The original target in-service date was May 2019. The actual in-service date was December 2019.

b) During the process of commissioning the station in the spring of 2019, additional commissioning requirements were discovered that had not been originally anticipated. These additional activities lead to the delay in final commissioning and to the increase in costs.

c) As per the response to Staff IR-4 in proceeding EB-2018-0328 (HHHI's ICM application), "As shown in HHHI's response to Staff IR-5, the independent consultant estimated the cost of MTS#1 at $25,268,526 (before capitalized interest in the amount of $794,000). HHHI was able to control costs resulting in the $23,476,441 submission which is $1,792,085 below the Engineer's budget (and includes the $794,000 capitalized interest costs)." At the time of the OEB-approved budget, HHHI had already managed to control many costs. As explained in part (d), "During the process of commissioning the station in the spring of 2019, additional commissioning requirements were discovered that had not been originally anticipated".

d) Confirmed. There is no contingency in the ICM Budget.

[4] EB-2018-0328, Interrogatory Responses, February 8, 2019, Appendix IRR-B.

e) During the commissioning process, a significant customer event occurred that caused unforeseen additional commissioning requirements.

f) Please HHHI's response 1-Staff IRR - 6 part e.

g) HHHI confirms that, as of the ICM application (EB-2018-0328), HHHI had spent $23,476,441 of the HHHI Board approved budget of $25,268,526 or 92.91%.

Capital Expenditures

2 - Staff IRR - 7

2-Staff-7
Ref: Exhibit 2/Section 2.5 Capital Expenditures

Question(s):

a) Please provide HHHI's forecast capital additions by investment categories (System Access, System Renewal, System Service, General Plant).

b) Please explain HHHI's approach to forecasting capital expenditures and related capital additions.

c) Please provide the year to date actual capital expenditures for 2020 by investment categories.

d) Please provide the historical (2016-2019) and the forecast (2020-2021) capital expenditures on vehicle expenses.

Response:

a) The following table, replicated from HHHI's DSP Section 4.11 (Table 58), provides HHHI's forecasted capital additions by investment category.

Table 58 – Capital Project Summary (DSP 4.11)

Capital Project Summary

	2021	2022	2023	2024	2025
System Access	$2,529,975	$1,810,370	$3,242,599	$2,999,303	$2,098,537
System Renewal	$2,362,090	$2,668,766	$1,427,270	$1,775,778	$2,425,404
System Service	$881,872	$1,110,667	$1,424,209	$967,525	$1,099,379
General Plant	$828,057	$582,400	$606,940	$694,260	$618,140
Total	**$6,601,994**	**$6,172,203**	**$6,701,018**	**$6,436,866**	**$6,241,459**
Contributed Capital	$1,135,176	$885,392	$1,479,197	$1,391,127	$997,281
Net Annual Budget	**$5,466,818**	**$5,286,811**	**$5,221,822**	**$5,045,738**	**$5,244,178**
System O&M	**$1,981,686**	**$2,031,229**	**$2,082,009**	**$2,134,060**	**$2,187,411**

b) HHHI's approach to forecasting capital expenditures and related capital additions can be found in section 4.10 "Investment Drivers" of HHHI DSP. This section of the DSP provides a description of HHHI approach to investments forecasting in each investment category.

c) Please see Table Staff IRR – 1 – 2020 Year to Date Actual Capital Expenditures by Investment Category.

Table Staff IRR – 1 – 2020 Year to Date Actual Capital Expenditures by Investment Category

Projects	2016	2017	2018	2019	2020 Bridge Year	2020 Actuals (Sept 30, 2020)	2021 Test Year
System Access							
Technical Service Layouts	498,615	27,946	516,348	278,232	172,435	161,228	147,325
Subdivisions	9,685	(64,875)	(53,594)	(83,035)	(22,244)	48,278	-
Renewable Generation	84,985	27,729	50,079	(419)	(4,439)	(87,608)	(5,525)
Wye-Delta Service Upgrades	-	-	-	3,587	80,788	6,261	79,774
Municipally Driven Projects	-	492	40,094	21,469	791,066	108,844	939,918
Make Ready work	13,865	7,122	14,000	(27,509)	2,697	16,491	1,622
Metering	24,252	152,049	301,016	421,185	435,914	251,744	231,685
Substation Projects	-	-	294,865	314,998	-	-	-
Miscellaneous	6,324	52,500	43,177	95,215	-	10,737	-
Sub-Total	637,726	202,963	1,205,985	1,023,723	1,456,217	515,975	1,394,799
System Renewal							
Pole Replacements	2,141,311	1,864,536	1,947,990	1,321,301	715,864	357,481	624,199
Poletrans Replacement Program	655,716	996,718	895,811	1,640,316	1,026,848	469,947	809,294
Porcelain Insulator Replacement Program	20,614	44,544	8,921	62,443	49,132	35,661	51,459
Transformer Replacement Program	134,640	115,133	102,772	184,143	84,716	82,999	222,791
Pole Line Rebuild Program	-	-	-	-	-	-	-
Substation Equipment	677,093	524,904	-	-	143,037	79,287	615,397
Distribution Equipment Renewal	-	2,859	18,052	22,576	-	1,865	38,950
Feeder Reinforcement	-	196,398	-	-	-	-	-
Vintage Replacements	1,135,736	664,363	958,143	-	50,811	12,536	-
Miscellaneous	131,001	124,806	217,355	114,630	-	9,097	-
Sub-Total	4,896,111	4,534,261	4,149,044	3,345,409	2,070,408	1,048,873	2,362,090
System Service							
Feeder Improvements	1,027,163	618,515	854,371	363,395	270,150	96,830	-
Voltage Conversion	402,232	340,409	431,712	607,962	939,061	646,318	463,908
Substation Upgrades	-	94,650	83,024	274,854	67,559	740	186,770
Automated Switches & SCADA Integration	243,887	282,226	252,088	489,670	248,475	126,318	231,194
Arrestor Program	-	-	-	-	-	-	-
Miscellaneous	325,226	238,070	151,301	263,908	-	(27,794)	-
Sub-Total	1,998,508	1,573,870	1,772,496	1,999,789	1,525,245	842,412	881,872
General Plant							
Equipment & Tools	208,845	527,523	249,768	238,686	290,000	193,108	525,000
Software & Systems	177,003	164,099	95,862	207,634	231,290	78,863	233,057
Building Equipment	96,013	69,864	114,023	99,582	100,000	11,476	70,000
Miscellaneous	9,047	-	36,711	107,832	-	(4,726)	-
Sub-Total	490,908	761,486	496,364	653,734	621,290	278,721	828,057
Miscellaneous							
Total	**8,023,253**	**7,072,580**	**7,623,889**	**7,022,654**	**5,673,160**	**2,685,981**	**5,466,818**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*							
Total	**8,023,253**	**7,072,580**	**7,623,889**	**7,022,654**	**5,673,160**	**2,685,981**	**5,466,818**

d) Please see Table Staff IRR – 2 – Historical and Forecast Vehicle Expenses below.

Table Staff IRR – 2 – Historical and Forecast Vehicle Expenses

Year	Vehicle Expense
2015	$ 99,327
2016	$ 452,929
2017	$ 354,379
2018	$ 208,373
2019	$ 98,276
2020	$ 312,179
2021	$ 495,000

Working Capital

2 - Staff IRR - 8

2-Staff-8
Ref: Revenue Requirement Workform (RRWF)

Question(s):

a) Please explain the difference between the controllable expenses of $7,432,968 in the RRWF, Tab 4. Rate Base, cell G24, and the proposed OM&A of $7,580,262 (RRWF, Tab 9. Rev Reqt, cell F15).

Response:

a) The difference between the controllable expenses of $7,432,968 in the RRWF, Tab 4. Rate Base, cell G24, and the proposed OM&A of $7,580,262 (RRWF, Tab 9. Rev Reqt, cell F15) is related to property taxes and fleet amortization expenses. Please see Table Staff IRR – 3 below.

Table Staff IRR – 3 – Controllable Expense Reconciliation

Distribution Expenses	RRWF Tab 4	RRWF Tab 9	Difference
Distribution Expenses - Operation	1,440,803	1,440,803	-
Distribution Expenses - Maintenance	458,000	458,000	-
Billing and Collections	1,177,856	1,177,856	-
Administrative & General Expenses	4,484,712	4,484,712	-
Donations - LEAP	18,890	18,890	-
Taxes Other than Income Taxes	157,546	-	157,546
Less Allocated Depreciation in OM&A	(304,840)	-	(304,840)
Total Eligible Distribution Expenses	**7,432,967**	**7,580,261**	**(147,294)**

Customer Engagement

2 - Staff IRR - 9

2-Staff-9
Ref: Exhibit 2/Distribution System Plan/Appendix B – Customer Engagement Results

Preamble:

In support of the 2021-2025 Cost of Service application, HHHI created a website to survey customers and gain an understanding of their preferences and perceptions.

Question(s):

a) HHHI noted that survey questions were reviewed by a customer focus group of eight customers prior to survey launch. Please explain key changes to the questions after the review of the customer focus group.

b) HHHI stated that customer response is strongly in favour of a proactive asset replacement strategy to improve reliability even if it results in increased costs. Did HHHI conduct any cost benefit analysis to examine the relationship between investments in asset replacement and the performance of system reliability?

c) In question six, HHHI asked customers "Sometimes power outages are caused by tree branches contacting lines. How much more would you be willing to pay each month for increased tree trimming to reduce power outages?" Please explain:

   i. What's the incremental cost in tree trimming that would result in an increase to customers' monthly bills for each of the three options presented to customers ($0-$0.5, $0.5-$1.5, $1.5-$3.0)?
   ii. What's the expected improvement (i.e. reduction to power outages) that can be achieved for each of the three options presented to customers ($0-$0.5, $0.5-$1.5, $1.5-$3.0)?

d) HHHI noted that while over 90% of customers support the concept of electronic billing, only 30% of customers have enrolled in paperless billing at the time of customer engagement.
   i. Please provide the number of customers that have enrolled in electronic billing as of October 30, 2020.
   ii. Please provide details of HHHI's plan for promoting electronic billing.
   iii. Please explain whether HHHI has included any cost savings resulting from electronic billing in its proposed 2021 OM&A. If so, please provide the forecast saving and explain the basis of the forecast.

Response:

a) The customer panel did not recommend any changes to the actual questions. They did recommend formatting changes to make the site and the survey easier to navigate and to make the questions easier to read. The site was updated based on these recommendations.

   In addition, the initial process required registration to the site to participate in the survey. This proved challenging for many users. As a result, the site registration was removed and instead the survey was updated to include questions up front that confirmed that the respondent was an HHHI customer. These updates ensured only eligible customers completed the survey but in a simpler to navigate format.

b) HHHI's approach to asset replacement focuses a proactive approach and replacement strategy to replace assets that are defective or are reaching end-of-useful life to plan, prioritize, and pace capital expenditures. HHHI completes a qualitative and quantitative analysis of project and project alternatives as identified in the capital project sheets. HHHI does not perform the specific cost benefit analysis examining the relationship between investments in asset replacement and the performance of system reliability because quantifying system reliability improvements is challenging since so many external factors contribute to reliability statistics.

c) Survey question six (#6)
   i. The question chose representative values consistent with the values chosen in other parts of the survey. The question was to gauge customer appetite to pay more for specific items rather than to quantify into a specific budget amount. The 2021 Test Year vegetation management budget is $300,000.

   ii. It is not possible to quantify a specific reduction in tree contacts tied to a specific dollar amount. Maintaining line clearances as required by code reduces the potential for tree contacts, however, it cannot eliminate them completely.

d) Electronic Billing
   i. A current total of 7,897 customers were enrolled in electronic billing as of November 3, 2020.

   ii. Electronic billing is promoted through HHHI's website and social media sites. For new customers or customers moving within Halton Hills, the default for billing is now electronic. Customers who utilize HHHI's online moving forms default to paperless billing unless they opt out. As well, customers who directly contact the customer service department are asked to provide an e-mail address for billing.

   A specific campaign to further promote e-billing has not been determined at this time.

   iii. HHHI has not included any additional cost savings resulting from electronic billing in its proposed 2021 OM&A.

Cost of Power

2 - Staff IRR - 10

2-Staff-10

Ref: Chapter 2 Appendices – 2-Z Commodity Expense
Regulated Price Plan – November 1, 2020 to October 31, 2021, October 13, 2020

On October 13, 2020 the OEB issued the Regulated Price Plan Report for November 1, 2020 to October 31, 2021.

a) Please update Appendix 2-Z with the new prices.

The Ontario Energy Rebate (OER) has changed from 31.8% to 33.2% starting November 1, 2020.

b) Please update Appendix 2-Z with the new OER credit.

Response:

a) HHHI has updated Appendix 2-Z with the new RPP prices. Please see Appendix Staff IRR – A.

b) HHHI has updated Appendix 2-Z with the new OER percentage. Please see Appendix Staff IRR – A.

Distribution System Plan

2 - Staff IRR - 11

2-Staff-11
Ref: Exhibit 2/Section 2.5.1 Planning

Preamble:

HHHI acquired an independent review of its Distribution System Plan (DSP) from Acumen Engineered Solutions International Inc. (AESI).

Question(s):

a) What's AESI's definition of Good Asset Management Practice and Good Utility Practice? Please explain.

b) Please clarify whether HHHI hired any consultant in support of its preparation of its DSP.

Response:

a) AESI utilizes the following definitions:

Good Utility Practice is as described in the Distribution System Code:

"*good utility practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America*;"

Good Asset Management is defined in the 2009 KPMG report to the OEB: Review of Asset Management Practices in the Ontario Electricity Distribution Sector as:

"*Consistent with good asset management practices, we identified the key processes as follows:*
- *Inspections and maintenance processes;*
- *Capital expenditure planning:*
- *Capital financing processes: and*
- *Information management processes*"

b) AESI reviewed the DSP and Appendices in its entirety and provided commentary and feedback along the way. These recommendations were incorporated into the final document and AESI completed a final review prior to issuing the letter.

2 - Staff IRR - 12

2-Staff-12
Ref: Exhibit 2 – Rate Base and DSP/p. 144

Preamble:

Decision Support System (DSS) is used for budgeting purposes based on asset age and condition.

Question(s):

a) Please explain the relationship between age and condition in DSS.

b) Please explain how condition is quantitatively calculated in DSS.

Response:

a) The Kinetrics Inc. useful life of asset report K-418022-RA-0001-R003 was used to determine the useful service life for the three (3) asset categories included in the DSS.

For pad and pole mounted transformers, age information is known but condition is not. For these assets, a linear degradation curve has been used. Similarly, substation data was evaluated based on useful life of assets.

HHHI undertakes annual pole testing and maintains these evaluations in a database. There are several in-situ non-destructive evaluation methods available for ascertaining a wood distribution pole's loss of mechanical strength primarily due to ground-line decay where moisture conditions are ideal for propagating and supporting fungal attack.

For poles, a combination of age and asset condition is used to calculate remaining useful life of the asset.

b) <u>Poles</u>:
The following evaluation methods are used by HHHI (to complement visual observations of advanced decay and extensive insect damage):

- Visual inspection of wood cross-arms and pole tops for signs of rot, feathering, insect and woodpecker damage and other signs of damage.
- Sounding the pole at various heights to check for weak points and visual checks for rot, decay and holes above and below ground line.
- Sonic stress wave evaluation - a sonic test signal is applied to each pole and is compared to a test database that includes pole strength. By comparing the test signal to that stored in the database for the same pole species, a measure of pole strength can be determined.
- Resistograph testing - Resistograph is a trademark process characterizing electronic high resolution needle drill resistance measurement devices used for inspecting timber in order to find internal defects and to determine wood density. With this testing method, a long, thin needle is driven into the wood. The electric power consumption of the drilling device is measured and recorded. Resistograph devices

are different from other resistance drills because they provide a high linear correlation between the measured values and the density of the penetrated wood.

The condition assessment data is captured in the DSS and used to calculate the remaining useful life of the asset.

Other Assets:
A linear degradation curve based on asset age and useful life of asset as determined by the Kinetrics report is used.

2 - Staff IRR - 13

2-Staff-13
Ref: Exhibit 2 – Rate Base and DSP/p.144

Preamble:

Section 1.2.6 of the DSP indicates that the implementation of DSS and improvements to the geographic information system (GIS) are changes to the asset management process.

Question(s):

a) Please explain the benefits of the DSS and the enhanced GIS, and explain how the implementation of DSS and improvements to GIS resulted in changes/improvements to the distribution asset management process.

Response:

a) Implementation of the DSS has assisted in the pacing and prioritizing of projects. The DSS shows the overall condition of assets based on various budget scenarios. This tool forecasts asset condition over a 25-year period based on current, increased or decreased budget scenarios. This long range forecasting provides insights into potential future impacts of changes in budget that were not possible previously.

HHHI has enhanced the information tracked in the GIS related to asset inspection information. As well, field interruption reports which track equipment repairs or replacements driven by power outages or customer calls are also tracked geographically. Reviewing asset information geographically assists HHHI in targeting future inspection or maintenance programs.

2 - Staff IRR - 14

2-Staff-14
Ref: Exhibit 2 – Rate Base and DSP/p.154

Preamble:

The table on page 20 of the DSP shows that the remaining available Feeder 1 capacity at substation 19 is 990 KW

a) Please explain how you arrived at this value.

Response:

a) The feeder capacity limit for this substation feeder is 1,440kW. The allocated capacity for this feeder is 450kW. The remaining capacity is 1440kW – 450kW = 990kW.

2 - Staff IRR - 15

2-Staff-15
Ref: Exhibit 2 – Rate Base and DSP/p.161

Preamble:

Table 12 on page 27 of the DSP shows power outages by cause and a statement is made that "second longest outages were related to defective equipment" and "the total number of outages hours related to defective equipment was less than half the previous year's total".

Question(s):

a) Please list the 15 major events that occurred in 2016.

b) Please explain why the number of outage hours attributable to defective equipment in some years are higher than that attributable to adverse weather (years 2015, 2017 and 2018).

c) Please explain the reason for significant variations in number of outage hours attributable to defective equipment over the historical period.

Response:

a) The 15 incidents that aggregate to qualify as a major event are all related to a freezing rain storm on March 24, 2016. There were multiple outages across HHHI's distribution system throughout the night and day totalling the 15 incidents as shown in Table 12. For the year 2016, HHHI's daily SAIDI threshold for a Major Event was 0.5338. The daily SAIDI for March 24, 2016 was 0.5476 thus the incidents qualify as a Major Event.

b) On average, it takes more time to determine the cause and/or locate defective equipment (patrol lines) where outages related to adverse weather is quite evident.

c) As described on page 165 of Exhibit 2 "the failure of certain types of assets such as porcelain switches and insulators have been the source of a number of larger power outages in the Town of Halton Hills. Through 2018 and 2019, HHHI replaced 11 porcelain switches and 4 porcelain insulators. HHHI plans to continue to proactively replace these devices in the field. HHHI's proactive replacement strategy has led to a reduction in equipment failure power outages".

   Outage hours attributable to defective equipment from 2015 to 2019 has decreased each year with the exception of 2018. On December 27, 2018, HHHI experienced a broken porcelain switch that fell and came into contact with a steel cross arm resulting in a pole fire that enveloped three (3) feeder lines that were on the same pole, triggering the breaker protection. Due to the situation where three (3) feeder lines were impacted at once, this incident contributed to 33% (1/3) of the total hours of outages in 2018 (and 75% of the defective equipment failure outage hours). While full restoration was completed within ninety (90) minutes, the total outage hours were large due to the number of customers affected. HHHI had indicated that defective porcelain switches and insulators were an issue in the 2016 Distribution System Plan. HHHI proactively replaces (as opposed to run to failure) porcelain switches and insulators when possible and will continue with this practice until the switches have all been replaced.

2 - Staff IRR - 16

2-Staff-16
Ref: Exhibit 2 – Rate Base and DSP/p.163

Preamble:

Figure 9 on page 29 of the DSP shows Supply Voltage Metrics.

Question(s):

a) Please explain what units are shown on the Y axis of this graph.

Response:

a) The Y-axis describes the number of voltage related events that once investigated were found to be either within the band of normal operating conditions outlined in CAN/ CSA C235-83 Table 3 "Service Entrances" or outside of the band of normal operating conditions.

2 - Staff IRR - 17

2-Staff-17
Ref: Exhibit 2 – Rate Base and DSP/p.170

Preamble:

Section 3.1.2 of the DSP describes Asset Management Planning Objectives.

Question(s):

a) Please explain why in Table 18 on page 36 of the DSP poles replacement and testing numbers are part of the Financial objective.

b) Please explain why there are no targets for some objectives, namely Smart Grid Implementation, Conservation and Fair Rates.

Response:

a) Financial goals focus on achieving the optimal trade-off between maintenance and replacement costs. That is, replacing assets only when it becomes more expensive to keep them in service, provided there is no identified safety risk. HHHI has adopted condition-based assessments rather than age-based replacement programs where practical to better pace and prioritize investments.

   As such, maintaining a target of 80-100 pole replacements per year ensures prudent capital expenditure, and avoids potential higher costs should the asset fail in the field.

b) Smart grid implantation focuses on implementing "smart" devices that will enable HHHI to have supervisory access and control of field devices such as automated switches. The focus in the 5-year forecast period is deployment and automation of distribution assets enabling HHHI greater visibility of distribution system conditions in near real time, and provide remote operation, thereby reducing time spent restoring power.

   Energy conservation targets existed under the prior CDM Framework, however, since the termination of that program, there have been no specific conservation targets set for LDCs.

   Similar to the smart grid implementation objective, fair rates is a more holistic objective around ensuring that projects balance customer's preference for improved reliability with the desire for reasonable rates. HHHI works to find the most cost efficient approach to asset management and distribution system planning that strikes a balance between reliability and affordability.

2 - Staff IRR - 18

2-Staff-18
Ref: Exhibit 2 – Rate Base and DSP/p.173

Preamble:

Figure 15 on page 39 of the DSP shows Asset Management Process Flow.

Question(s):

a) Please explain which data inputs are used for assessing system capacity needs.

b) Please explain which data inputs (e.g. useful life of rolling stock, IT equipment, building improvements, expanding storage facilities, need for new meters, SCADA improvements, etc.) are used for assessing General Plant needs.

Response:

a) System capacity needs are derived using a number of sources including municipal growth planning (ie: development applications) and new customer load described in section 4.2 of the DSP. That information feeds into HHHI's business and strategic plans (strategic input) in Figure 15. From the strategic inputs, HHHI evaluates asset condition, remaining useful life, and long-term system operability (data inputs) when assessing system capacity.

b) General Plant spending is driven by maintaining and replacing equipment and tools, building equipment and software and systems.

   Tools and equipment are evaluated based on age and condition as well as safety and ergonomic considerations.

   Age and condition of vehicles factor into the equipment and tools category. Most vehicles are replaced every 10 to 12 years. Other equipment such as trailers, stringing machines & forklifts are evaluated on a 20-year replacement cycle.

   The GIS register is used to support the asset management program and as such must be kept as up to date as possible. As new system assets are installed or removed, asset alteration data is input into the register. The software is updated periodically as the vendor creates new versions and the host systems are specified to ensure that the hardware platform is appropriate. HHHI will be upgrading its GIS system within the period of the plan.

   Projects in General Plant also include information technology upgrades aimed at addressing cyber security risks and complying with Ontario Energy Board (OEB) "Ontario Cyber Security Framework" and reporting requirements set forth in OEB EB-2016-0032.

   In 2021, HHHI intends to replace the garage roof. The garage roof has not been replaced since the building opened in about 1990.

2 - Staff IRR - 19

2-Staff-19
Ref: Exhibit 2 – Rate Base and DSP/p.173, p.384

Preamble:

Asset Management Plan (AMP) is referred to on page 39 of the DSP as a document containing asset condition assessment. This AMP document in turn refers to DSS for deriving Asset Performance Distribution for various assets. Section 4.4.2 of the DSS in Table 7 shows purely age-based condition triggers that are then combined with budget inputs in Table 8 in section 4.5.1 of the DSS to generate Condition Performance Distribution for all asset categories.

Question(s):

a) Please provide formulae used in calculating condition of assets using Health Index score that quantitatively incorporates factors other than age.

b) Please provide Health Index distribution for distribution assets based on the latest calculated conditions.

c) Please explain the basis for budgetary amounts in Table 8 of the DSS.

d) Has HHHI considered options other than replacement in developing these budgets?

Response:

a) The formulae used to calculate asset condition is proprietary to the DSS. For utility poles, the formulae incorporated asset condition based on annual pole testing results as well as age to calculate Health. Transformers, which are a run to failure asset, were calculated based on age alone. Most substation data was based on age alone, however, condition was incorporated for power transformers where they had been rewound.

b) The information presented in the DSP and the Asset Management Plan is the most up to date information available at this time.

c) The budgetary figures used were approximated values based on 2019 budget values and an estimated forecast of the 2020 budget based on the best information available at that time.

   These budgets were used for planning purposes only. The DSS is a Decision Support System; a tool used to assist in asset planning. As such, it is an additional input into existing asset management planning but it does not directly drive decisions without considering other factors.

d) <u>Poles</u>: As poles deteriorate, rehabilitation or replacement is typically the only viable options. Generally, rehabilitation such as patching holes or using boron rods to mitigate carpenter ant damage, only prolongs the eventual failure and increases the potential for increased quantities of poles requiring replacement resulting in increased spending. HHHI, only replaced poles that are deemed defective. HHHI maintains a proactive replacement strategy for distribution poles since failure could have significant safety and or reliability consequences.

Transformers: Transformers are a run to failure asset. As such, they are typically replaced when they fail, or if inspections indicate a significant deterioration such as leaking oil or shifting on the pad.

Substation equipment is proactively replaced as the consequence of failure is high. However, switchgear and power transformers can be refurbished to extend their useful life. This is done where feasible from the perspectives of cost, safety and reliability.

2 - Staff IRR- 20

2-Staff-20
Ref: Exhibit 2 – Rate Base and DSP/p.175

Preamble:

The DSP refers on Page 41 to a system modelling software.

Question(s):

a) Please provide detailed description of the distribution modelling software.

b) Please explain how this software was used to assess systems capacity needs.

Response:

a) As stated on page 41of the DSP "HHHI utilizes distribution system modelling software to make assessments of system capacity to accept new customer loads such as large commercial development and residential development. The software allows us to make an assessment of capacity at a feeder and local level, assess constraints, and put measures in place to mitigate issues that could impact supply to customers. Distribution system modelling is performed on a case-by-case basis. Where known development is forthcoming and may impact other development, HHHI makes an assessment of all known projects to have a holistic understanding of system impacts, if any, and put measures in place to mitigate impacts."

   Please note, the last sentence on page 14 should read "Figure **18** *[emphasis added]* below shows our distribution system modelling software".

b) As stated in the DSP, where known development is forthcoming and may impact other development, HHHI makes an assessment of all known projects to have a holistic understanding of system impacts, if any, and put measures in place to mitigate impacts.

   Where the system modeling indicates potential adverse conditions such as low voltage, HHHI can assess mitigation measures and plan for capital investments to resolve the adverse condition.

2 - Staff IRR - 21

2-Staff-21
Ref: Exhibit 2 – Rate Base and DSP/p.178

Preamble:

Section 3.3.6 on page 44 of the DSP refers to reliability risk/consequence analysis.

Question(s):

a) When was this analysis performed?

b) Please indicate where in the DSP this analysis could be found.

Response:

a) A basic contingency analysis was performed during the DSP preparation to explore the reliability risk of the loss of a station transformer.

b) This analysis is found in Sections 3.4.14.4 to 3.4.14.6 on pages 67 through 71 of the DSP.

2 - Staff IRR - 22

2-Staff-22
Ref: Exhibit 2 – Rate Base and DSP/p.178

Preamble:

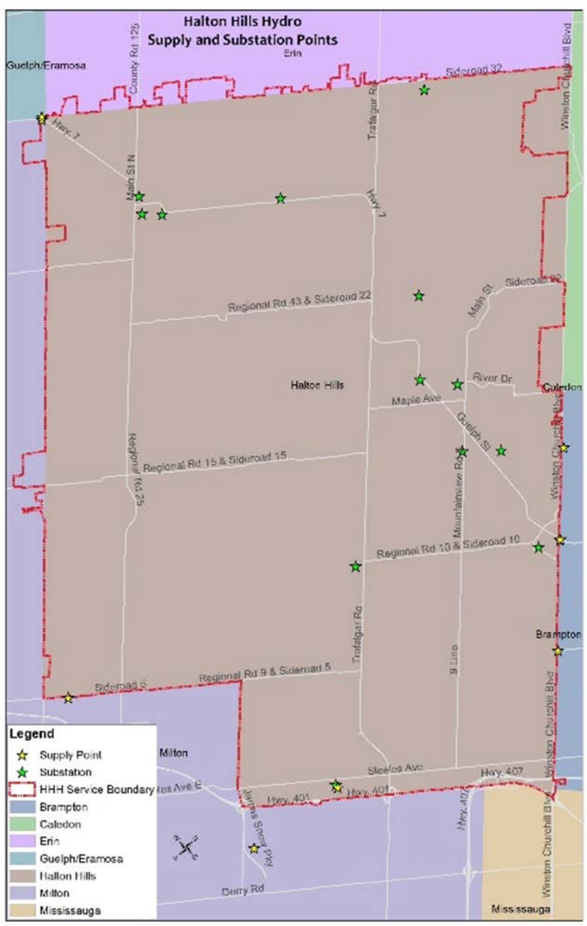
Section 3.4.2 on pages 45 and 46 of the DSP provides information on HHHI's system configuration.

Question(s):

a) Please provide a single line summary diagram showing the main supply points and feeders.

Response:

a) Figure 21 of HHHI's DSP shows the supply points from Hydro One and Halton Hills MTS #1 and is replicated below. A description of those supply points is provided in section 3.4.2 of the DSP.



2 - Staff IRR - 23

2-Staff-23
Ref: Exhibit 2 – Rate Base and DSP/pp.178 and 180

Preamble:

Figure 19 on page 44 of the DSP shows the Average Number of Times that Power to a Customer is Interrupted (SAIFI) and the Average Number of Hours that Power to a Customer is Interrupted (SAIDI) historical trends for 27.6 kV and 44 kV feeders.

Question(s):

a) Please explain why reliability performance of 1M2 and 1M5 feeders originating at Halton Hills MTS #1 and referred to on page 46 of the DSP are not shown.

Response:

a) HHHI has not included statistics for feeders 1M2 and 1M5 as they were both put into service near the end of 2019. At the end of 2019 the 1M5 did not have any load on it.

2 - Staff IRR - 24

2-Staff-24
Ref: Exhibit 2 – Rate Base and DSP/p. 189

Preamble:

The table at the bottom of page 55 of the DSP shows risk-based transformer vaults ranking.

Question(s):

a) Please explain how these risk rankings were assigned/determined.

Response:

a) A site specific risk assessment was undertaken for each location and is detailed in Appendix A of the Asset Management Plan as follows:

"B.2 Site Specific Risk Assessment

The sites below are ranked in terms of priority based on physical assessment, customer responsibility and overall risk.

Transformer vault rooms are owned by the owner of the building in which they are located. Halton Hills Hydro owns and operates the transformers, switches, and primary cabling inside the vault. As such a site evaluation of the transformer vaults in Halton Hills was conducted to assess the state of the vaults and associated risks. The following is a prioritized assessment ranked highest to lowest.

Rank #1: Maria Street Apartments, Acton.

This site consists of two apartment buildings supplied radially from Church Street. There is a single riser pole with cutouts switches that supply two 3-phase vault transformers B03V084 and B03V086, one in each building. Figure B.1-6 shows the location of these two vaults.

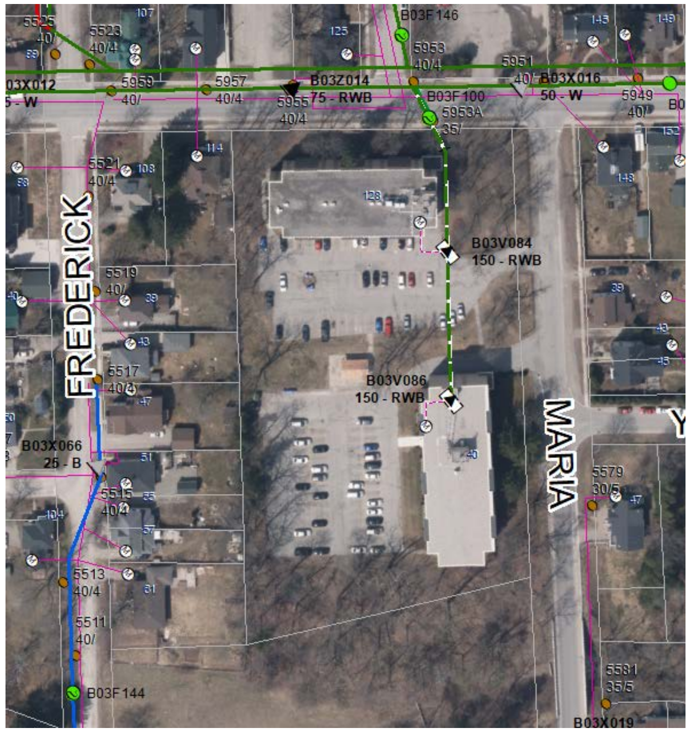


Figure B.1-6: Halton Hills Distribution System for Maria Street Apartments.

These transformers are radially supplied from Church Street. A site assessment identifies:

1. The doors are hard to open.
2. There is limited room inside the vault rooms to maintain and operate the switches safety.
3. There are signs of transformer heating.
4. Further, since the supply is radial, if the upstream primary cable is damaged or the first transformer is isolated both buildings will be isolated affect many residents.

Figure B.1-1 shows the transformers in B03V086. Consideration should be given to the safety of personnel operating the switches inside the vault rooms as well as impacts to customers affected when the upstream transformer has to be isolated. A proactive replacement of these two transformers with padmounted units and a distribution loop would improve reliability for these customersAn assessment of options for replacement should be conducted in the next 5 years.

Rank #2: Centennial Public Elementary School, Georgetown

This site consists of three single phase transformers banked together providing 3-phase power to the school. The transformers are located within walled enclosure exterior to the building alongside the parking lot. The top of the enclosure is open to natural air. Entry to the enclosure is through two double doors. Figure B.1-7 shows the vault location. The enclosure is owned by the Halton District School Board, the transformers are owned by Halton Hills Hydro.

Figure B.1-7: Centennial Public School, Georgetown

Figure B.1-8: Transformer Vault at Centennial Public Elementary School

A site assessment reveals the following concerns:

1. The locking mechanism on the double doors could be easily broken.
2. The doors are made of plywood.
3. There are no signs indicating what is behind the doors or the electrical hazard within.
4. There is a ground lead cut at grade and not bonded to the enclosure. This also presents a tripping hazard as you enter the enclosure. Furthermore, only one door is bonded to ground. Both should be as there are metal framing for each door.
5. Interior crossing arm supporting secondary bus is rotting.
6. Metal fenced "roof" was installed by the school to keep children out.

The risks associated with this location are primarily related to the enclosure. The school board should be contacted to address these concerns.

Rank #3: Plaza, 10 Mountainview Road South, Georgetown.
The transformer vault at this plaza is supplied from an overhead 3-phase energized at 4160Grd-Y/2400V. Access to the transformer room is gained at the rear of the plaza and is vented. Inside the vault room are three single phase transformers that are banked together suppling 3-phase power to the building. Figure B.1-9 shows the condition of the transformer vault.

Figure B.1-9: The transformer vault door and transformers within.

A site assessment identifies the following issues:

1. The door was padlocked with an unknown hasp lock.
2. There are signs of transformer heating and oil leaking. Transformers appear to be rusting.
3. There were signs that general public had gained access to the vault room and were using it as a hang-out.

These transformers should be inspected annually with a short-term plan to replace them one-for-one or with a padmounted transformer within the next 5 years.

Rank #4: Moore Park Plaza
This site is supplied form a set of three single phase transformers banked together to supply this commercial multi-unit plaza (C08V148). Entrance to the vault room is gained from the rear of the building. There is a single vent with fan in the exterior wall of the room. Figure B.1-10 shows the transformer vault door.

Figure B.1-10: Transformer Vault Door.

A site assessment indicates the following:

1. The door frame is rusting and damaged. Along the floor the frame is cracked.
2. The door does not sit properly in the frame and is difficult to open and close.
3. The concrete footing of the wall near the door frame is cracking and falling apart.
4. The transformers are in good condition.
5. There are no signs indicating what is behind the doors or the electrical hazard within.

The concerns relating to this location relate to the door. The building owner will need to address these concerns.

Rank #5: Multi-Unit Commercial Site, 29 Armstrong Avenue
This site is supplied from a set of three single phase delta transformers banked together providing 600V 3-phase 3-wire supply to three buildings on site. The transformers are Westinghouse and are dated 1966. The room contains two vents mounted high on the exterior wall. Access is gained from a single door on the outside of the building. Halton Hills Hydro owns the transformer within the vault room. Figure B.1-11 shows this vault room.

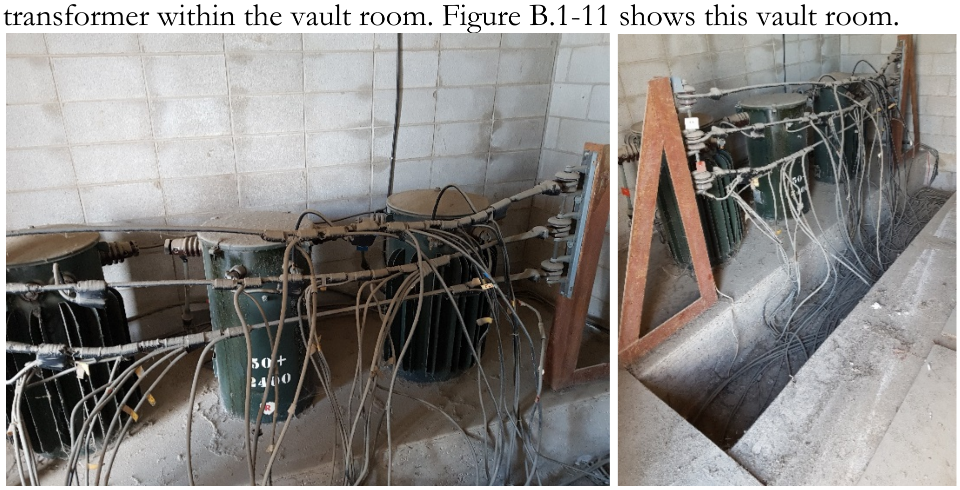


Figure B.1-11: Transformer vault room at 29 Armstrong Avenue

An assessment of this site identifies the following:

1. Transformer are delta, 600V 3-wire is supplied to the building.
2. Replacing transformers could be difficult.
3. Transformers have surpassed their Useful Service Life however they appear to be in good condition.

There are no immediate safety concerns with this site. Halton Hills Hydro should take samples of the oil in each transformer and have them tested for PCB's.

Rank #6: Multi-Unit Residential Build, 115 John Street, Georgetown

The multi-unit residential building at 115 John Street in Georgetown is supplied from an underground distribution system to transformer C10V109 located on the main floor at the rear of the building. The supply is 3-phase 4 wire, 4.16Grd-Y/2.4kV stepped down to 600Y/347V. The vault room is in good condition, clean, and the exterior door opens without problem.

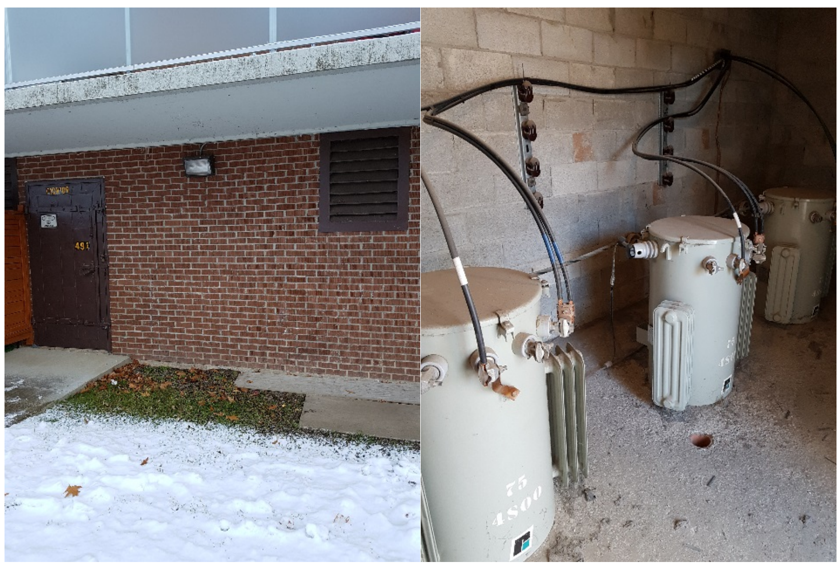


Figure B.1-12: Transformer vault room at 115 John Street, Georgetown

While there are no issues of significant concern in respect of this transformer vault, a decal on the exterior door is recommended to advise the public and first responders of the contents of the vault room.

3 - Staff IRR - 25

2-Staff-25
Ref: Exhibit 2 – Rate Base and DSP/p. 190

Preamble:

Figure 28 on page 56 of the DSP shows age distribution of PoleTrans transformers and describes below how the replacement priority was driven by their risk factors.

Question(s):

a) Please explain how risk factors were determined, including how probability of failure was incorporated in deriving them.

Response:

a) A site specific analysis of existing PoleTrans transformers was utilized in evaluating risk. Due to equipment obsolescence and known safety concerns in maintaining these devices, a proactive replacement strategy has been adopted.

HHHI has adopted a proactive replacement strategy to remove all Pole-Trans transformers within its service area. Pole-Trans units are being replaced with modern padmounted transformers and new primary distribution cable is being installed to supply these transformers. This strategy upgrades these systems to better accommodate future growth and eliminates obsolete equipment from the distribution system. A proactive approach to replacing these assets ensures improved reliability going forward. A failed pole-trans transformer would result in a lengthy outage to restore power as spare parts are no longer available.

Over the course of the next five (5) years HHHI shall continue to design and replace end of useful life PoleTrans units on an annual basis and eliminate such devices from HHHI's system. The priority of expenditure shall be ranked by risk factors including:

- Addressing areas with known safety risks to those operating the distribution system or known areas where our distribution system is at risk.
- Number of customers affected a potential outage and potential length of outages.
- Age and condition of the PoleTrans and cable in specific areas.
- Capital budget constraints.

This proactive approach ensures that HHHI's equipment is safe to operate and reliability is improved.

2 - Staff IRR - 26

2-Staff-26
Ref: Exhibit 2 – Rate Base and DSP/p. 191 and 223

Preamble:

HHHI states on pages 57 and 89 of the DSP states that it is developing a primary cable testing program.

Question(s):

a) Please describe what specific testing protocol will be used.

b) Please explain how test results will be used in determining condition of underground cables.

c) Does HHHI expect to replace or refurbish any underground primary cables based on the test results within the forecast period?

Response:

a) The testing protocols that are used in primary cable testing are those employed by Cable Q, a division of Hydro Ottawa, and developed by the National Research Council Canada (NRC). The testing is non-destructive. Details of the methods for cable testing are identified in Appendix E of HHHI's Asset Management Plan SP20-01.

b) The cable testing results gathered through individual cable testing provide a health score, $\%Q_{DEP}$. The parameter is based on the change in the depolarization current waveform of the aged cable under test. The result is a $\%Q_{DEP}$ value that can be used to determine the condition of the cable under test as outlined in Table 1 "Limits of the $\%Q_{DEP}$ Parameter for Various Cable Insulation Conditions" Cable Q's report in Appendix E.

c) Should primary cable be identified as in poor condition through testing, HHHI will evaluate remedial options to mitigate potential impacts of a cable failure.

2 - Staff IRR - 27

2-Staff-27
Ref: Exhibit 2 – Rate Base and DSP/pp.191-193

Preamble:

Table 29 on pages 57-59 of the DSP lists a significant number of customer owned substations within HHHI's service territory.

Question(s):

a) Please describe how load losses attributable to the failure of equipment at these substations is accounted for in calculating system SAIFI and SAIDI.

Response:

a) Load losses attributable to the failure of equipment at customer owned substations are accounted for in the same manner as distribution system equipment failures. The resulting customers affected and duration are added into the overall SAIDI/SAIFI calculations.

   Unplanned outage hours attributable to the failure of equipment at customer owned substations is included in SAIFI and SAIDI numbers. If an outage is reported, crews will isolate the service and the outage is considered over. Any additional hours, after isolation of the service, are not included in the SAIFI and SAIDI numbers.

2 - Staff IRR- 28

2-Staff-28
Ref: Exhibit 2 – Rate Base and DSP/p.320

Preamble:

Table 7-5 on page 52 of the AMP shows the list of MS transformers and their oil condition, loading and age and then states that "based on DSS analysis, once the Willow MS transformer is replaced, other power transformers are expected to remain in acceptable condition within the window of this plan, with 2029 targeted for the next transformer replacement". Table 7-5 also states that Willow transformer needs to be replaced due to age.

Question(s):

a) Please explain why Willow MS transformer needs to be replaced because as stated throughout the DSP age is not the same as condition and transformer oil is in a good condition.

b) Please explain how the condition of MS transformers differs from their age and what is the formula used to quantitively calculate condition of these transformers.

c) Please explain why Ballinafad MS transformer with the same oil condition as Willow transformer and similar loading is not expected to be replaced over the next nine years even though it is only three years younger than the Willow MS transformer.

Response:

a) The primary driver for replacement of the Willow MS transformer is age. Stated in the project sheet for 2021, HHHI is being proactive in mitigating the higher risk of an aged asset being left in service. Replacement of this transformer in 2021 also mitigates the risk associated with large capital investments to replace more than one substation transformer in later years if the aged asset were left in service and subsequently fails.

b) An MS transformer condition is based on factors include its physical condition, quality of insulating oil and age. Factors affecting a transformer's condition include environmental and system loading. A transformer may have surpassed its useful life but still be in good condition if it is maintained. Likewise, a transformer may not have surpassed its useful life but be in poor condition depending on environmental contaminants, weather, maintenance and loading characteristics.

   HHHI has not used a specific formula in developing our strategy for planned capital investments for substation transformers, however, analyzing the results in the DSS helps inform decisions.

c) Please refer to section 4.12.4.1.2 "Substation Equipment" of the DSP and the 2025 project sheets. HHHI's DSP includes capital investments to replace Ballinafad MS's transformer in 2025.

2 - Staff IRR - 29

2-Staff-29
Ref: Exhibit 2 – Rate Base and DSP/pp. 195, 198 and 199

Preamble:

It is stated on page 61 of the DSP that Halton MTS has eight feeders yet Table 35 on page 64 of the DSP and Figure 31 on page 65 of the DSP only show loading information for six feeders.

Question(s):

a) Please provide loading for the remaining two feeders.

b) Please confirm that except for the 1M2 feeder all other feeders originating at Halton MTS carry no load.

Response:

a) Table 35 in HHHI's DSP provides feeder capacity. At the time of writing the DSP, HHHI has not commissioned the 7th and 8th feeders and as such is not in a position to state the capacity of the remaining two (2) feeders. The feeder average peak loads for 2015 – 2019 reflect the currently commissioned six (6) feeders and the available capacity.

b) At the time of writing the DSP, all other commissioned feeders were not carrying any load.

2 - Staff IRR - 30

2-Staff-30
Ref: Exhibit 2 – Rate Base and DSP/pp. 199-200

Preamble:

Section 3.4.14.1 on pages 65 and 65 of the DSP provides system capacity assessment which is based on average feeder loading that assumes that all feeders are equally loaded.

Question(s):

a) Please explain the meaning of 6MVA existing feeder surplus in the contingency analysis on page 65 of the DSP.

b) Other than average post-contingency feeder loading calculations provided in this section, has HHHI performed a formal capacity assessment study using load flow analysis?

c) If answer to b) is "yes" please provide a document describing this analysis.

d) Please describe load transfer capabilities among the nine 44 kV and 27.6 kV feeders.

Response:

a) The surplus described incorrectly states MVA as the unit of measure. This should have read a surplus of 6 "Feeders" rather than "MVA".

b) No, HHHI has not performed a formal capacity assessment study using load flow analysis.

c) Not applicable.

d) Load may not be transferred between the 44 kV system and the 27.6 kV system.

With regard to the 44 kV feeders, the three (3) feeders from Pleasant TS may transfer load among themselves within HHHI's distribution system. The HHHI load on the single 44 kV feeder from Fergus TS may be transferred to Pleasant TS. There is limited capability to transfer Pleasant TS load to Fergus TS due to poor power quality resulting from extended feeder line voltage drop. Further, load transfers between the two (2) TS's are avoided for planned work in order to avoid double peak billing charges from the upstream distributor.

Load transfer capabilities exist among the 27.6 kV feeders as well. The Halton TS feeder loads may be transferred via tie switches in the HHHI distribution system. There are also double peak billing costs when transferring between the Halton TS M21 and either of the Halton TS M29 or M30 feeders. The Halton Hills MTS # 1 feeder loads may also be transferred to other HH MTS 1 feeders via distribution system tie switches. Consideration is being made to create the future ability to transfer load between Halton TS and Halton Hills MTS # 1.

2 - Staff IRR - 31

2-Staff-31
Ref: Exhibit 2 – Rate Base and DSP/pp. 201-205

Preamble:

Section 3.4.14.4 on pages 67-71 of the DSP describes 4.16 kV system assessment.

Question(s):

a) Please explain how the ability to accept load transfers constraints the system ability and does not provide sufficient redundancy.

Response:

a) The existing Georgetown 4.16 kV feeder loading is generally high at peak periods during the summer months. Load transfers are needed at times to ensure reliability by reducing the possibility of overloads. The high loading among many of the feeders reduces the ability to accept transfers from other feeders. Additional feeders are required to provide redundancy to reduce the loading overall among the feeders and decrease the requirement to perform temporary load transfers. The high feeder loading also means that station maintenance must be performed in the spring and fall when the loading is reduced and the adjacent station feeders are better able to accept a load transfer from the station that is out of service. Operations experience has also shown that poor power quality conditions exist at times when feeder load transfers are in effect. This is due to voltage drop along the feeder conductors when loading is increased and lines are extended to feed areas served by a station that is out of service for maintenance.

2 - Staff IRR - 32

2-Staff-32
Ref: Exhibit 2 – Rate Base and DSP/p. 205

Preamble:

Figure 36 on page 71 of the DSP shows asset management factors and then it states that these factors are considered when assessing asset's condition.

Question(s):

a) Please provide a quantitative formula that show how these factors were used for different asset categories to determine their condition.

b) Please explain how the impact of failure, public safety and worker safety factors are used in determining assets' condition.

c) Please explain how an "Asset Condition" factor is used in determining asset condition.

Response:

a) Prudent capital planning does not allow for all assets to be replaced based on age alone. Rather, these other factors are considered when prioritizing which assets get replaced in a given year. These factors are not considered based on a quantitative formula. Rather, they are assessed on a case by case basis.

For example, pole replacements are prioritized based on the following criteria:
- The age and condition of the pole.
- The proximity of the pole to public gathering spaces, i.e. a vintage pole located adjacent to a school or recreational facility has a higher priority than a pole located in a rural area.
- The highest voltage available on the pole, i.e. a vintage pole carrying a 44 kV sub-transmission feeder has a higher priority than a pole that supports only a low-voltage overhead bus.
- The impact on system reliability, i.e. a vintage pole carrying backbone distribution circuits has a higher priority than a pole that supports fused lateral circuits.

Other factors and opportunities, i.e. if there is an opportunity to carry out a voltage conversion project or other modernization effort in conjunction with the pole replacements, these poles will be assigned a higher priority than otherwise would have been the case.

b) An asset condition is determined by several means specific to the asset. For major assets such as poles, substation transformers, oil filled regulators, and substation switchgear, condition assessment can include in-depth testing and visual inspections. As stated in 3.5.1.1 of the DSP, the factors listed in (b) and shown in Figure 36 are considered when assessing an asset's condition. Analysis of factors such as worker and public safety as it relates to operating an aged asset are considered when HHHI is deciding to rehabilitate or renew an asset.

c) The "asset condition" factor shown in Figure 36 of HHHI's DSP is an assessment of the assets' condition. Inspections and in-depth testing (ex. oil testing for transformers, non-destructive pole testing) provide data that contribute to an overall assessment of a specific asset. An asset's condition assessment contributes to HHHI's proactive strategic planning from which to base capital expenditures for renewal or replacement prior to an assets failure.

2 - Staff IRR - 33

2-Staff-33
Ref: Exhibit 2 – Rate Base and DSP/p. 206

Preamble:

Section 3.5.1.3 of the DSP on page 72 states that changes in System Renewal expenditures affect budgets for the other three categories.

Question(s):

a) Please explain how these changes affect System Access expenditures majority of which are demand driven.

Response:

a) Since System Access expenditures are primarily customer driven, System Renewal budget changes have the least impact on this category. However, there are ways in which the System Renewal and System Access budgets are linked.

   For example, System Renewal projects can offset some System Access expenditures. If HHHI is aware of planned development in an area where it is undertaking a System Renewal project, HHHI can evaluate potential needs of forthcoming development to ensure asset renewals can accommodate the future development (ie: taller poles for circuit capacity, larger transformers).

   System Access project schedules are often highly variable as they are driven by third party schedules. If System Access projects (such as road widening) are deferred by the third party, HHHI may reallocate part of that budget to System Renewal in the given year.

2 - Staff IRR - 34

2-Staff-34
Ref: Exhibit 2 – Rate Base and DSP/pp. 206-207

Preamble:

Section 3.5.1.4 of the DSP on pages 72 and 73 describes maintenance practices and criteria for various asset categories.

Question(s):

a) Please explain how the results and observations from these maintenance activities are incorporated into calculating condition of assets.

b) Please explain how the results and observations from these maintenance activities are used in determining what is the appropriate course of action, i.e. refurbishment or replacement.

Response:

a) HHHI performs routine inspections on the assets discussed in 3.5.1.4 "Maintenance Planning Criteria Assumptions". The results of the inspections are used to plan for asset refurbishment or renewal. Each asset listed in this section of the DSP requires unique and specific tests in addition to observations. As an example, HHHI performs annual standard oil testing and dissolved gas analysis (DGA) testing on each of our substation transformers. The results of the tests are compared from year-to-year to determine if the transformer oil is degrading. Certain types of gases such as ethylene and acetylene can indicate excessive heating and possible shorted core windings. The results of specific tests are used to address degradation, perform risk based assessment of the asset before the asset fails so the asset can be proactively maintained or replaced to address the issue. Observations of the physical condition of the equipment are documented. Where an issue (ex. leaking gasket, excessive rust) is found, those issues are addressed through maintenance or capital budgets as befits the necessary work.

b) Please see HHHI's response 2 – Staff IRR - 34 part a.

2 – Staff IRR - 35

2-Staff-35
Ref: Exhibit 2 – Rate Base and DSP/p.208

Preamble:

Figures 37 and 38 and page 74 of the DSP explain the risk-based project prioritization approach.

Question(s):

a) Please explain how risk impact in Figure 38 is determined.

b) Please explain how risk probability in Figure 38 is determined.

Response:

a) Risk impact is determined by evaluating the potential impact on the distribution system and public safety that could result from asset failure. The figure below is HHHI's corporate risk assessment impact ratings guidelines. This guideline helps in the decision making process when evaluating risks. As stated on page 74 of the DSP, risk impact is scored from 1 to 5 where 1 is not significant and 5 is catastrophic requiring immediate attention. As an example, a pole in an urban residential location alongside a sidewalk that supports 3-phase distribution supplying a subdivision has a greater impact if it fails that would a pole in a rural setting, alongside a road with little or no public in the immediate area. Hence, pole in the urban environment has a greater risk factor if it were to fail as it presents a higher risk to the public and greater number of customer affected by a power interruption.

Impact Rating Guidelines						
Severity		1. Insignificant	2. Minor	3. Moderate	4. Major	5. Catastrophic
Type of Risk	Financial	Minimal or no Financial Impact	Minor financial impact	Moderate financial impact	Large financial impact	Significant financial impact
	Reputation	Concern expressed by one stakeholder	Significant concerns raised by one stakeholder, short term negative media focus	Significant concerns raised by more than one stakeholder, negative media focus	Significant concerns raised by more than one stakeholder, long term negative media focus	Stakeholder loses confidence in the organization or several stakeholders withdraw support
	Operational	Event can be managed through standard operations	Event requires actions greater than routine activity	Significant event but can be managed under routine activity	Critical event with long recovery period and requires significant management	Disaster with the potential to lead to the collapse of the organization
	Health, Safety & Environment	Reportable Incident	Reportable incident with minor injuries	Serious injuries	Significant injuries or long term health implications	Loss of Life

b) The risk probability as described on page 74 of the DSP, is a ranking from 1 to 5 where 1 is lowest risk and 5 is the highest risk. As an example, a pole that is determined as being defective by a qualified pole testing company has a higher probability of failure than a pole that is good condition. Hence, the failed pole will have a probability of failure risk greater than a pole in good condition. The numeric score assigned can depend on past performance of assets in similar conditions. The following table is HHHI's risk likelihood rating guideline that is used to guide decisions about the asset replacements. The two (2) tables, Impact Rating Guidelines and Likelihood Rating Guidelines are used together, along with other sources of information, as part of HHHI's evaluating risks and making decisions about asset replacements.

Likelihood Rating Guidelines			
	Description	Occurrence Frequency	Probability
1. Rare	May only occur in exceptional circumstances	Once >10 Years	Less than 20%
2. Unlikely	Could occur during a specified time period	Once every 5-10 years	21-40%
3. Somewhat Likely	Might occur within a 5 year time period	Once every 1-5 years	41-60%
4. Likely	Will probably occur in most circumstances	Once per year	61-80%
5. Almost Certain	Expected to occur in most circumstances	Multiple times per year	Greater than 80%

2 - Staff IRR - 36

2-Staff-36
Ref: Exhibit 2 – Rate Base and DSP/p.213

Preamble:

Section 4.2 on page 79 of the DSP refers to in-house software used to determine required changes to the HHHI's system to accommodate new developments.

Question(s):

a) Please describe the software's functionality and outputs.

b) Please explain whether it was used for assessing future feeders' loadings.

c) If "yes", how was it used in conjunction with average feeders' loading calculations described on pages 65-66 and 67-71 of the DSP?

Response:

a) HHHI uses a software program called DESS. The software contains a functional model of HHHI's distribution system in which transformers, wire and cable, switches, customer load, and generation are modelled to reflect the devices in the field, and customer load. HHHI can add a development (ex. subdivision) to the model and analyze the impacts on feeder loading, voltage, current flow, and fault currents to determine if HHHI's distribution system requires enhancements or upgrades to support the development.

   Outputs of the software include voltage, current (amps), load loading, fault current and impedance, and voltage/ current imbalance.

b) HHHI did not use DESS software to evaluate substation feeder capacity and average load discussed in the DSP from pages 65 to 71 outlined in question (c) below.

c) Not applicable.

2 - Staff IRR - 37

2-Staff-37
Ref: Exhibit 2 – Rate Base and DSP/p.219

Preamble:

Section 4.6 of the DSP on page 85 refers to the DSS being used to evaluate asset condition.

Question(s):

a) Please point out where in the DSS asset condition is determined using more than age alone.

b) Please explain what you mean by "continual condition assessment".

Response:

a) Presently, the DSS has three asset types: poles, distribution transformers and substation transformers/ switchgear. In the DSS, pole asset information relates to pole age and condition assessments from annual pole testing. The DSS is a tool HHHI has begun leveraging in helping to make asset replacement decisions. As indicated in section 3.5 of HHHI's DSP and HHHI's Asset Management Plan SP20-01, there are many factors that contribute to HHHI's decision to renew or replace assets.

b) A continual condition assessment refers to HHHI being proactive in the approach taken to managing the assets bulleted on page 85 of the DSP. HHHI has annual programs such as pole test and oil sampling that are done at regular intervals on a continual basis to assess the assets condition and take proactive steps to address issues that arise before the asset fails.

2 - Staff IRR - 38

2-Staff-38
Ref: Exhibit 2 – Rate Base and DSP/p.246-248

Preamble:

Tables 54, 55,56, and 59 on pages 112-118 of the DSP show projects within System Access, System Renewal and System Service investment categories along with the forecasted amounts for each project and projects' drivers. The projects named in these tables within each Investment Category are different than the project titles used in justifying material projects in Appendix E "Capital Projects Sheets".

Question(s):

a) Please provide Table 59 Detailed Capital Projects in working Microsoft Excel format.

b) Please provide a table assigning each of the material capital projects in Appendix E to one of the line item listed in Table 59 Detailed Capital Projects. Please ensure the sum of material projects reconcile with information filed in Table 59 Detailed Capital Projects.

Response:

a) Please see attachment Halton_Att_2-Staff-38a_CapitalProjects_20201125.

b) Please see attachment Halton_Att_2-Staff-38b_CrossReference_20201125.

Exhibit 3 – Revenues

Conservation and Demand Management (CDM) Variable in Load Forecast

3 - Staff IRR - 39

3-Staff-39
Ref: Exhibit 3, Table 4, page 16
Load Forecast Model, Tab CDM
2019 Participation and Cost (P&C) Report
2017 Final Verified Savings Results Report

Preamble:
The persistence savings in the CDM Variable in the load forecast could not be reconciled with the 2019 Participation and Cost (P&C) Report. The discrepancies are shown by year:

Savings persistence into 2021 from following program year	Quantum of CDM Savings in 'CDM Variable'	2019 Participation and Cost (P&C) Report
2016	6,215,530 kWh	6,323,403 kWh
2017	7,512,733 kWh	9,389,654 kWh
2018	2,730,021 kWh	3,287,635 kWh
2019	970,290 kWh	294,918 kWh
2020 (half year rule applied)	813,319 kWh (0.5 x 1,626,637 kWh)	Not available

Question(s):

a) Please discuss why HHHI did not include 2016 and 2017 unverified adjustments (as identified in 2019 P&C Report) in the CDM Variable of the load forecast.

b) Please clarify why the 2018 savings of 2,730,021 kWh in the CDM Variable do not match the reported savings in the 2019 P&C Report (3,287,635 kWh).

c) For 2019 actual savings embedded in the CDM Variable, please explain why savings of 970,290 kWh have been used rather than the results in the 2019 P&C Report (294,918 kWh).
    i. Please discuss why these additional savings of 675,372 kW were not captured in the 2019 P&C Report, but should be included in the CDM Variable.

d) Please provide the breakdown of 2019 and 2020 program savings by project, in excel format, showing the following detailed information:
    i. What framework the project is being completed under (for example, Conservation First Framework (CFF) wind-down program, interim framework, etc.)
    ii. The timing of approval for each project

iii. Confirmation that the utility and its customer(s) have entered into a contractual agreement for the energy efficiency project(s) to be completed
iv. The total estimated savings and project timeframe for each project(s) that HHHI is contractually obligated to complete

Response:

a) HHHI's adjustment to the load forecast was intended to be consistent with the LRAMVA which was populated using the 2017 verified results and IESO published persistence reports. The 2019 P&C report does not provide sufficient details to populate the LRAMVA model.

b) Please see HHHI's response 3 – Staff IRR – 39 part a.

c) Please see HHHI's response 3 – Staff IRR – 39 part a.

d) 2019 & 2020 CDM program savings
   i. Please see Halton_Att_3-Staff-39d_2019-2020CDM_20201125.

   ii. Please see HHHI's response 3 – Staff IRR - 39 part d (i).

   iii. Please see HHHI's response 3 – Staff IRR - 39 part d (i).

   iv. Please see HHHI's response 3 – Staff IRR - 39 part d (i).

3 - Staff IRR - 40

3-Staff-40

Ref: Exhibit 3, Table 14, p. 24
Load Forecast Model, Tab "Summary"
2019 Participation and Cost (P&C) Report

Preamble:

In Exhibit 3, Table 14, HHHI notes that load was adjusted downward for savings from customer 1 based on the implementation of a Process & System Upgrades Program (PSUP) – Combined Heat and Power (CHP) CDM program. Savings of 3,169,000 kWh were reflected in a separate "Direct CDM Adjustment" as shown in the Summary Tab (cell M8) of the Load Forecast model. HHHI notes that including these savings in the CDM Variable to the load forecast would result in double counting.

Question(s):

a) Please provide additional information on when the PSUP – CHP CDM program was undertaken, when the savings were achieved, and under which CDM framework that project was completed under.

b) Please provide a copy of the Measurement & Verification (M&V) report to validate the 2020 savings of 3,169,000 kWh achieved by customer 1, including all persisting savings in future years if available.
    i. If there is no M&V report, please explain the methodology used to estimate energy savings, including measurement of the base case and the new level of demand with the CHP project in operation.

c) Please confirm whether 3,169,000 kWh of savings from customer 1 are net savings achieved in 2020. If not, please apply a net-to-gross ratio to calculate the net savings.

d) Please confirm whether the half year rule was applied on 3,169,000 kWh savings. If not, please discuss why the half year rule should not apply.

e) Please confirm whether or not the CDM Variable in the 2021 load forecast includes savings of 3,169,000 kWh from customer 1.
    i. If yes, please explain why there should be a separate adjustment per Table 14.
    ii. If not, please explain how double counting of the CDM savings would occur.

Response:

a) The PSUP – CHP CDM program has not been completed yet. The expected time of completion is now late summer/fall of 2021 due to Hydro One Network Inc. timelines related to impact agreements and possible upgrades. The PSUP – CHP CDM program will be completed under the Conservation First Framework CDM framework.

b) There is no M&V report to validate the savings. Please see part c below for the calculation of the savings.

c) Estimated Net Energy (kWh) = Pre-Project Consumption Savings (5,000,000) x Probability Factor (.8) x IESO Net Energy Ratio (0.79225)

Where:

- Pre-Project Consumption Savings is the Gross Energy Savings estimate provided by the Applicant
- Probability Factor is a local adjustment to the Gross value based on the Stage of the application (Stage – Pre Approved has a probability factory of 80%, which is 0.8 in formulas. This is used to provide a conservative estimate of the savings in case the project does not proceed beyond the Pre-Approved Stage. As an application progresses toward completion this factor increases up to 100% when the application is Post Approved.
- Net to Gross Ratio is supplied by the IESO. All applications have a Net to Gross ratio applied. Savings are reported on a Net value. The Net to Gross Ratio is a factor of Incentive Type, Track and Measure Category

Thus, 3,169,000 = 5,000,000 x 0.8 * 0.79225

Estimated Savings apply only to projects that have not been submitted yet for Post Approval. After Post Approval, the Actual Net Savings are used.

d) HHHI confirms that the half year rule should have applied to savings from customer 1.

e) CDM variable for Customer 1

   i. Page 24, lines 9 and 10 of Exhibit 3 states the following; "The adjustment for Customer 1 reflects the 2020 implementation of a PSUP – CHP CDM program which was not included in the CDM variable to ensure a double count did not occur. ". Therefore, HHHI confirms that the adjustment was not included in the CDM adjustment.

   ii. Please see HHHI's response 3 – Staff IRR - 40 part e (i).

3 - Staff IRR - 41

3-Staff-41
Ref: Load Forecast Model

Question(s):

a) If there are any revisions to the savings included in the CDM Variable, please summarize the adjustments in response to this interrogatory and explain any updates made to the Load Forecast Model.

b) If there is any supporting documentation filed in response to the above interrogatories, please ensure that all confidential information that may be filed in your responses be removed or treated in accordance with Rule 9A of the OEB's *Rules of Practice and Procedure*.

Response:

a) There are no revisions to the savings included in the CDM Variable.

b) Not applicable.

Load Forecast

3 - Staff IRR - 42

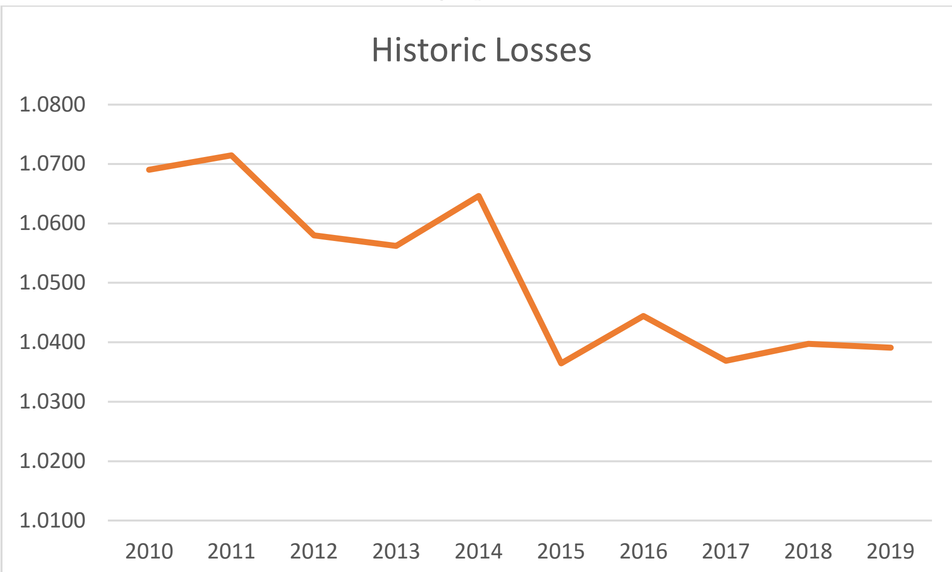
3-Staff-42

Ref: Load Forecast Model - Rate Class Energy Model tab
Chapter 2 Appendix 2-R

Preamble:

HHHI has used a ten-year historic average of losses to estimate losses in the test year. OEB Appendix 2-R uses a five-year historic average of losses to estimate losses in the test year. The loss factor in the load forecast model when all ten years are used is 1.0516. When only the last five years are used, the loss factor is 1.0393.

The ten years of historic losses are graphed below:



Question(s):

a) Does HHHI believe that the difference in losses between the earlier years relative to the later years is due to random variability, or due to systemic changes in its line losses?

b) If HHHI believes that the difference in line losses over the years is due to systemic changes, such as upgrades to lines, please explain why a ten-year average was chosen.

Response:

a) Without a historical line loss study, HHHI cannot confirm with complete accuracy whether the change is due to variability or systemic changes. HHHI can confirm that it used a ten (10) year average in its LF to align with the policy of running an ten (10) year regression analysis whereas the policy with respect to the requirements around Appendix 2-R is to use a five (5) year average. HHHI has followed the board requirements with respect to both calculations.

b) Please see HHHI's response 3 - Staff IRR – 42 part a.

3 -Staff IRR - 43

3-Staff-43
Ref: Exhibit 3, pages 24, 31

Preamble:

HHHI identifies three customers that have resulted in a reduction of load in the General Service 1,000 to 4,999 kW rate class. With respect to one, it states "The adjustment for Customer 1 reflects the 2020 implementation of a PSUP – CHP CDM program". A second customer is permanently closed. The third "reflects the reduction in operation for which occurred prior to COVID-19." The regression model includes a variable for the outlet mall, but not any of the three customers above.

Question(s):

a) Please provide details on the timing of the load loss of each of the three customers.

b) If the load lost from any of the customers was in 2019 or prior, was an explanatory variable tested in the load forecast similar to the outlet mall?

c) If the load lost from Customer 3 was in 2020, please provide the load prior to and after the reduction in operation, and explain why the same adjustment was made to both the General Service 1,000 to 4,999 kW rate class, and the General Service 50 to 999 rate class.

Response:

a) Customer 1 is still not complete and the load loss is not expected until late summer/early fall 2021.

   Customer 2 load loss occurred in July 2020.

   Customer 3 load loss in the General Service 1,000 to 4,999 kW class occurred in Spring 2020, however, the load decrease was effective in early 2019 (HHHI performs rate class changes early in the calendar year unless requested by the customer).

b) HHHI confirms that the suggested variable was not tested as a scenario as the impact of customer 3 was not as significant as the Outlet Mall.

c) While the load loss began in early 2019, the customer did not change rate classes until early in 2020. HHHI notes that the adjustment is not the same for both classes, the adjustment is added from the GS 50-999 and removed from the GS 1000-4999.

3 - Staff IR - 44

3-Staff-44
Ref: Exhibit 3, page 25

Preamble:

HHHI states that “At the time of preparing this evidence there was no indication that consumption levels would return to the pre-COVID-19 levels within the test year.”

HHHI has used COVID-19 Adjustments of 5% to Residential, -6% to General Service < 50 kW, and -9% to General Service 50 to 999 kW and General Service 1,000 to 4,999 kW.

Question(s):

a) Please provide HHHI’s actual monthly energy and demand by rate class for 2019 and all available months of 2020.

b) Please comment on the changes observed in 2020, and any observed impact of COVID-19. Please separately address the closure in March-May, and any changes resulting from the gradual re-opening that followed.

c) Does HHHI expect that the COVID-19 related reductions will persist past the test well into the 2022-2025 Incentive Rate Making (IRM) years. If so, please explain the rationale.

d) If HHHI does not believe that the COVID-19 related reductions will persist well into 2022-2025 years, please comment on the suitability of preparing a load forecast that is normalized for weather, but incudes adjustments one-time events that are not expected to persist substantially into the following IRM period.

e) Please provide a derivation of the COVID-19 adjustments used, or explain the methodology used for their selection.

Response:

a) HHHI’s actual monthly energy and demand by rate class for 2019 and all available months of 2020 are shown below in Table Staff IRR – 4 and Table Staff IRR – 5 below.

Table Staff IRR – 4 – 2019 Actual Monthly Energy and Demand

2019	Units	Residential	GS<50	USML	GS 50-999 kWs	GS 1000-4999 kWs	Street	Sentinel	Totals
January	kWhs	18,972,098	4,804,004	81,598	12,965,100	6,697,929	102,724	20,270	**43,643,722**
	kWs	-	-	-	32,183	14,638	257	54	**47,132**
February	kWhs	16,803,808	4,466,859	81,435	11,921,505	6,015,402	85,935	20,119	**39,395,063**
	kWs	-	-	-	32,515	14,403	257	54	**47,229**
March	kWhs	16,793,159	4,657,859	79,916	12,684,765	6,978,277	84,523	22,026	**41,300,524**
	kWs	-	-	-	34,229	17,969	257	59	**52,515**
April	kWhs	14,429,384	3,934,543	79,917	11,762,763	7,357,128	71,612	20,814	**37,656,160**
	kWs	-	-	-	33,221	18,680	257	56	**52,215**
May	kWhs	14,086,697	3,805,253	79,916	12,117,418	7,644,269	65,022	20,399	**37,818,973**
	kWs	-	-	-	33,824	18,722	257	55	**52,859**
June	kWhs	16,426,348	3,865,988	79,917	12,034,248	7,652,841	58,628	21,792	**40,139,762**
	kWs	-	-	-	37,316	19,295	258	59	**56,928**
July	kWhs	21,582,652	4,460,845	79,916	13,719,617	8,084,396	62,979	20,905	**48,011,311**
	kWs	-	-	-	37,355	19,976	258	56	**57,645**
August	kWhs	19,241,170	4,247,695	79,916	12,995,082	8,107,878	70,938	20,930	**44,763,608**
	kWs	-	-	-	36,366	19,768	258	56	**56,449**
September	kWhs	15,109,768	3,785,898	79,876	12,140,765	7,841,956	78,458	21,247	**39,057,967**
	kWs	-	-	-	36,261	19,428	258	58	**56,004**
October	kWhs	14,529,022	3,865,819	79,874	12,402,976	7,938,625	92,383	21,975	**38,930,673**
	kWs	-	-	-	36,640	19,206	262	60	**56,167**
November	kWhs	15,964,618	4,202,796	79,876	12,698,983	7,685,429	99,072	21,701	**40,752,475**
	kWs	-	-	-	34,538	18,921	262	59	**53,780**
December	kWhs	18,172,192	4,557,111	79,874	12,922,123	6,631,989	107,330	19,702	**42,490,322**
	kWs	-	-	-	34,161	18,085	262	53	**52,562**

Table Staff IRR – 5 – 2020 Actual Monthly Energy and Demand

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**
October	kWhs									**-**
	kWs									**-**
November	kWhs									**-**
	kWs									**-**
December	kWhs									**-**
	kWs									**-**

b) HHHI's observation of the impact of COVID-19 for April, May and June supports HHHI's COVID-19 discussion as shown in Exhibit 3, Table 15 on page 26 indicating that COVID-19 has an impact. Residential consumptions have increased where General Service consumptions and demands have decreased. Please see Table Staff IRR – 6 and Table Staff IRR – 7 for comparisons. Of note, the General Service 1,000 to 4,999 kW class shows a decrease in April as all businesses were shut down, however, as most of the customers in this class are involved in the food industry, they were deemed essential and continued operations.

Table Staff IRR – 6 – 2020 COVID-19 as compared to 2019 consumptions and demands

	Units	Residential	GS<50	GS 50-999 kWs	GS 1000-4999 kWs	Totals
April	**kWhs**	1,233,125	(607,754)	(1,401,013)	(954,519)	**(1,719,824)**
	kWs			(5,290)	(1,107)	**(6,394)**
May	**kWhs**	3,319,146	(440,565)	(920,854)	44,016	**2,013,044**
	kWs			492	1,034	**1,533**
June	**kWhs**	4,868,785	(176,201)	19,126	574,783	**5,294,085**
	kWs			(1,193)	995	**(198)**

Table Staff IRR – 7 – 2020 COVID-19 as compared to 2019 consumptions and demands shown as a percentage

	Units	Residential	GS<50	GS 50-999 kWs	GS 1000-4999 kWs	Totals
April	**kWhs**	8.546%	(15.447)%	(11.911)%	(12.974)%	**(4.57)%**
	kWs			(15.922)%	(5.926)%	**(12.25)%**
May	**kWhs**	23.562%	(11.578)%	(7.599)%	0.576%	**5.32%**
	kWs			1.455%	5.521%	**2.90%**
June	**kWhs**	29.640%	(4.558)%	0.159%	7.511%	**13.19%**
	kWs			(3.197)%	5.155%	**(0.35)%**

c) The current COVID-19 challenges are having a direct impact on the customers of HHHI. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and HHHI's business are not known at time. However, HHHI has already been notified by some general service customers, that their business will be closing permanently as a result of COVID-19, thus HHHI believes that the affects will be persisting past the test year and well into the 2022-2025 IRM years.

d) Please see HHHI's response 3 – Staff IRR – 44 part c.

e) HHHI's derivations is:

<table>
<tr><th></th><th>Residential</th><th>GS<50</th><th>GS 50-999 kWs</th><th>GS 1000-4999 kWs</th></tr>
<tr><td>IESO Report</td><td>+5%</td><td>Average(13)%</td><td colspan="2">Average (16.5)%</td></tr>
<tr><td>HHHI derivation</td><td>+5%</td><td>Half of IESO report assuming (6)%</td><td colspan="2">Just over half of IESO reporrt assuming (9)%</td></tr>
</table>

3 - Staff IRR - 45

3-Staff-45
Ref: Exhibit 3, page 20
Load Forecast Model, Tab: Rate Class Energy Model, Tab: Summary

Preamble:

HHHI states:

> For all other classes, HHHI has assumed the number of customers / connections will remain at the 2019 level in 2020 and 2021. HHHI submits this is a reasonable assumption since HHHI is not aware of a reason for the customer / connection numbers to increase or decrease over the forecast period especially with the recent impact of COVID-19.

The customer and connection counts are labelled "Year End Customers" and "Year End Connections" on the Rate Class Energy Model tab but are used as the forecasted customers on the Summary tab, and elsewhere throughout the application.

Question(s):

a) Please explain what the customer / connection numbers reflect – for instance whether they are year end, or an average value. If these are an average value, please explain how the average was calculated – for instance, an average of beginning and end, a 12-month average, or other method.

b) Please provide the customer connection count for the most recent month available.

Response:

a) The customer / connection numbers reflect year end numbers. HHHI would note that for rate design purposes, average numbers were used.

b) The most recent customer / connection counts available is September 2020 and is shown in Table Staff IRR– 8 below.

Table Staff IRR - 8 – Customer / Connections at month end September 2020

Rate Class	Customer / Connections
Residential	20,499
General Service less than 50 kW	1,800
General Service 50 to 999 kW	228
General Service 1,000 to 4,999 kW	10
Unmetered Scattered Load	182
Sentinel Lights	175
Street Lighting	4,846

3 - Staff IRR - 46

3-Staff-46

Ref: Exhibit 3, pages 30, 37
EB-2015-0074, Exhibit 3, Tab 2, Schedule 1, October 2, 2015, page 25

Preamble:

HHHI's 2012 Actual consumption in the Sentinel Lights class was 439,446 kWh with 650 kW of demand. The 2016 Approved amount was 416,109 kWh and 628 kW. From 2016 Actual to 2021 Proposed, the energy consumption is at most 273,180 kWh, and the demand is at least 680 kW. The following explanation was provided: "In the Sentinel Light class, the actual 2016 kWh for both actual and weather normalized were significantly less than Board Approved due to a calculation error related to the expected move to monthly billing."

Question(s):

a) Please explain the calculation error resulting from the move to monthly billing.

b) Please explain the circumstances that lead to a reduction from 461,109 kWh Approved to 273,180 kWh Actual in combination with an increase in billed demand.

c) Please explain why the 2016 to 2019 billed demand is higher than the 2012 billed demand, while the 2016 to 2019 energy consumption is lower than the 2012 energy consumption.

Response:

a) When investigating the change to monthly billing, HHHI's billing department was examining the sentinel light accounts to determine how many would need to be changed from bi-monthly to monthly. At that time, some discrepancies were noticed between those sentinels lights already billed monthly and others that were billing bi-monthly. Additionally, it was determined that a system rate class specific to sentinel lights would be beneficial for ensuring the consumptions were attributed to the correct Sentinel Light class. At that time, an audit of the sentinels was conducted and the audited values were verified with the system billing. Any incorrect values were corrected and all sentinel light accounts were updated with a new class distinguisher.

b) The 2016 to 2019 billed demand is higher than the 2012 billed demand as a result of the audit of the sentinel lights, a correction to many of the accounts that were billing bi-monthly but the demand had only been calculated for one month and the beginning of a change to more energy efficient sentinel lights.

   The 2016 to 2019 energy consumption is lower than the 2012 energy consumption as a result of the audit of the sentinel lights, a correction to many of the accounts and the beginning of a change to more energy efficient sentinel lights.

c) Please see HHHI's response 3 – Staff IRR – 46 part b.

3 - Staff IRR - 47

3-Staff-47

Ref: Exhibit 3, pages 30, 37, 38

Preamble:

In 2016 (Actual), the Street Light energy consumption was 1,832,979 kWh. In 2019 Actual, consumption was 979,604 kWh, a decrease of 46.6%. The 2016 demand was 5,129 kW and in 2019 it was 3,105 kW, a decrease of 39.5%.

HHHI discussed replacement of high-pressure sodium bulbs with LED as a reason for the decrease in load.

Question(s):

a) Please explain why the energy usage has decreased by a greater percentage than the demand.

Response:

a) When the Town of Halton Hills replaced the high-pressure sodium bulbs with LED bulbs, two (2) separate audits were done. The first audit was a geo-locate of all the streetlights that were to be change. The second audit occurred as the lights were changed. With each change, the ballast and bulbs were recorded and compared to the streetlight profile. As a result of the audits, a more complete and accurate streetlight profile was completed and maintained.

Exhibit 4 – Operating Expenses

2021 OM&A

4 - Staff IRR - 48

4-Staff-48
Ref: Exhibit 4/page 10

Preamble:

HHHI stated that "After the Executive Management Team's rigorous review and updated for any necessary changes, draft budgets were presented to HHHI's Board of Directors for final approval."

Question(s):

a) What changes have been made to the 2021 OM&A and capital budgets after the Executive Management Team's review?

b) Please provide the year to date actual OM&A costs for 2020 by OM&A programs.

Response:

a) The Executive Management Team made the following changes to:

2021 OM&A -

- Reduced the request for three new Full-time Equivalent Employees (FTE) to two (2) new FTE's
- Reduced vegetation management by $75,000

2021 Capital Budget -

- Reduced capital budget (Net of Contributed Capital) from $5,777,780 to $5,466,822; a reduction of 5.4%

b) Table Staff IRR – 9 represents the 2020 year to date actual costs up to September 30, 2020 by program.

Table Staff IRR – 9 - 2020 YTD Actual OM&A Costs by Program

Distribution Expenses	2020 Bridge Year - YTD September 30, 2020
Distribution Expenses - Operation	1,291,597
Distribution Expenses - Maintenance	261,812
Billing and Collections	800,487
Community Relations	-
Administrative & General Expenses	2,657,819
Donations - LEAP	17,917
Taxes Other than Income Taxes	123,352
Total Eligible Distribution Expenses	**5,152,984**

4 - Staff IRR - 49

4-Staff-49
Ref: Exhibit 4/page 23

Preamble:

HHHI stated that "Executive Management meets with HHHI's Board of Directors for a formal presentation and receipt of approval, subject to any required changes recommended by the Board of Directors."

Question(s):

a) Please provide a copy of the presentation made to the Board of Directors.

b) What changes have been made to the 2021 OM&A and capital budgets after the Board of Directors' review?

Response:

a) Executive Management made its formal presentation of the 2020 Bridge Year budget to HHHI's Board of Directors on November 28, 2019. The presentation provided to the Board of Directors to inform their deliberations regarding approval of the 2020 Bridge Year budget is not public information and forms part of the confidential Board proceedings.

b) The budgeting process requires the approval of HHHI's Board of Directors to establish an annual budget. The 2021 Test Year OM&A budget has not changed since it was established by the approval of the Board of Directors on February 7, 2020. The deliberations of the Board of Directors regarding its approval of the 2021 Test Year OM&A budget are confidential.

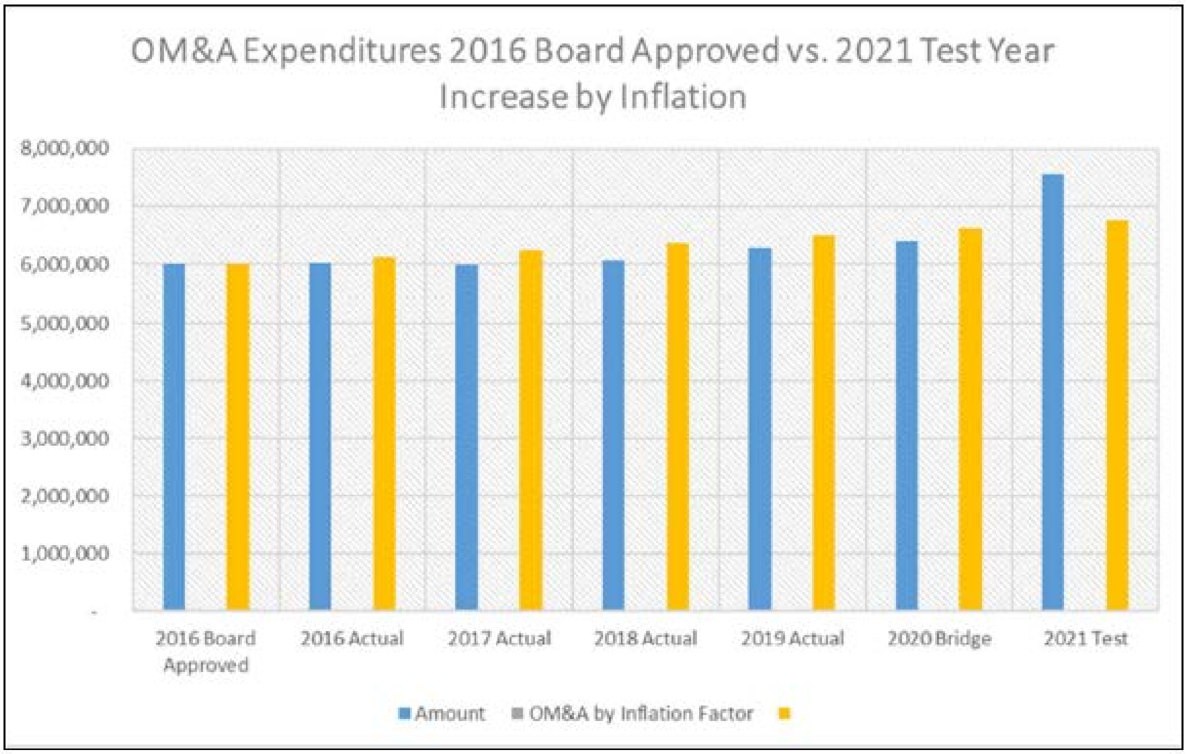
4 -Staff IRR - 50

4-Staff-50
Ref: Exhibit 4/page 16

Preamble:

HHHI provided a bar chart to show year over year change in OM&A with inflation increase.

Table 4 - Year over Year Change in OM&A (with inflation increase)



Question(s):

a) Please confirm the blue bars represent the OEB-approved (2016), actual (2016-2019), and forecast (2020-2021) OM&A costs.

b) Please confirm the orange bars represent OM&A costs with inflation increase.

c) Please specify the OM&A costs with inflation increase for the 2021 test year.

d) Please discuss why the proposed 2021 OM&A is reasonable (higher than OM&A with inflation increase) considering that HHHI managed its actual spending at a level lower than OM&A with inflation increase for each of the year over the 2016-2020 period.

Response:

a) Confirmed.

b) Confirmed.

c) OM&A costs with inflation from 2016 to 2021 Test Year is based on 2016 Board Approved $5,995,565 increase by an estimated inflation of 2% each year.

d) HHHI has presented the cost drivers for the proposed increase in Exhibit 4, Section 4.2.4, Table 12 on page 29 (shown below for ease of reference). HHHI has managed its actual spending between Cost of Service applications due to HHHI's "Relentless Incrementalism" which has avoided some costs. However, it should also be noted that HHHI did not reach it's deemed ROE, even in 2016, a Cost of Service year and in fact, earned well below the +/- 300 basis points that would trigger a Cost of Service review by the Board.

Table 12 - Cost Driver Table – OEB Appendix 2-JB[5]

Description	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Bridge Year**	**2021 Test Year**	
Opening Balance (Excluding LEAP & Property Taxes)	**$5,995,565**	**$6,012,139**	**$5,976,346**	**$6,052,225**	**$6,288,183**	**$6,406,370**	**$5,995,565**
Salaries and benefits							
Pay Equity Adjustment			$181,775				$181,775
Increase in FTE				$53,750	$65,373	$250,324	$369,447
Increase in wages and staff progressions						$103,906	$103,906
Increase in benefit costs						$82,967	$82,967
Change in labour burden allocation						$120,698	$120,698
Training and staff development				$58,645	($5,658)		$52,987
Professional Service			$38,500		($115,655)		($77,155)
Bad Debt expense	($114,548)	$107,007	($12,500)				($20,041)
Climate Change (Admin)						$279,700	$279,700
Cybersecurity and IT Training			$13,142	$36,706	$71,293	$91,300	$212,441
Transformer Station (Insurance, Control Room)				$1,086	$138,680	$50,586	$190,352
Mtce Operations (Switch Mtce)						$23,535	$23,535
Trucking costs				$65,730	($20,891)	$37,608	$82,447
Underground cable testing (ENG)					($39,940)	$25,000	($14,940)
Metering (wireless communication costs)						$24,680	$24,680
Regulatory						$16,000	$16,000
Materials and other cost increases					$31,357	$7,138	$38,495
Vegetation Management	$84,855	($181,855)	$6,567	($34,174)	$72,259	$25,000	($27,348)
Other	$46,267	$39,055	($151,605)	$54,215	($78,631)	$16,560	($74,139)
Closing Balance (Excluding LEAP & Property Taxes)	**$6,012,139**	**$5,976,346**	**$6,052,225**	**$6,288,183**	**$6,406,370**	**$7,561,372**	**$7,561,372**

OM&A Cost per Customer

4 - Staff IRR - 51

4-Staff-51

Ref: Appendix 2-L Recoverable OM&A Cost per Customer
2019 Yearbook of Electricity Distributors

Preamble:

Appendix 2-L provides OM&A cost per customer as follows:

	Last Rebasing Year 2016 - OEB Approved	Last Rebasing Year 2016 - Actual	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
OM&A Costs							
O&M	$1,729,772	$1,857,325	$1,657,609	$1,601,073	$1,569,890	$1,626,597	$1,898,803
Admin Expenses	$4,265,793	$4,154,814	$4,318,737	$4,451,152	$4,718,293	$4,779,773	$5,662,569
Total Recoverable OM&A from	$5,995,565	$6,012,140	$5,976,346	$6,052,225	$6,288,183	$6,406,370	$7,561,372
Number of Customers	26,978	27,152	27,387	27,650	27,826	28,040	28,147
OM&A cost per customer							
O&M per customer	$64	$68	$61	$58	$56	$58	$67
Admin per customer	$158	$153	$158	$161	$170	$170	$201
Total OM&A per customer	$222	$221	$218	$219	$226	$228	$269

Question(s):

a) Compared with 2016 actual, the proposed 2021 OM&A cost per customer will increase 21%. Compared with 2019 actual, the proposed 2021 OM&A cost per customer will increase 19%. Please explain how customers will benefit from this increase.

b) Using the 2019 Yearbook of Electricity Distributors, please compare HHHI's OM&A cost per customer with a peer group of local distribution companies (LDCs). Please explain the criteria for peer group selection and provide the list of selected LDCs. Please discuss the comparison results.

Response:

a) As described in the application, Exhibit 4, Section 4.2.4 – Cost Drivers, many of the increases are related to legal/regulated and mechanistic requirements. For example, the pay equity adjustment is a legal obligation that HHHI has carried since 2018 in the amount of $181,775 per year. Also, the Board amended section 5.1.3 (b) of the Distribution System Code requiring all distributors to install MIST meters on customer facilities where the customer has a monthly average peak demand during the calendar year of over 50kW. As these MIST meters require wireless communication, the communication costs must be incurred as annual OM&A.

In December 2017, the OEB issued its Ontario Cyber Security Framework with the objective to increase security and privacy in LDC's, with the overall goal of reducing cyber risk and improving service resilience. The new IT analyst position will bring some much needed in-house knowledge and focus to the overall health and maintenance of all IT/OT networks including telecommunications, network administration, hardware/ software, backup/ recovery and cybersecurity operations. Without the new IT analyst position, HHHI will continue to pull existing staff off of their regularly scheduled tasks to work as a team to support existing systems and rely on external vendors to implement new technologies. Customers will benefit from having the IT department focussed on systems that protect their privacy and maintaining training and protections against cyber threats.

Additionally, HHHI commissioned the new MTS#1 which included addition OM&A costs related to the land, building and control room. The new Transformer Station will help customers with reliability through redundancy circuits and avoidance of transformation connection charges. Additionally, the availability of the MTS#1 allows for the possibility to transfer load to avoid double peak billing when transfers are needed.

As an innovative, environmentally conscious utility, HHHI is ensuring its distribution system is future proofed to address customer choice and prepare for climate impacts. HHHI is planning ahead to ensure a resilient distribution system and to facilitate customer choice. This type of climate planning expenditure is being recognized as an imperative across the globe. Customers will benefit with more choice and a more resilient distribution system given the increased number and severity of climate change events.

b) Using the 2019 Yearbook of Electricity Distributors, HHHI determined the most relevant peer LDCs are:

- Canadian Niagara Power Inc.,
- Festival Hydro Inc.,
- Innpower Corporation,
- Milton Hydro Distribution Inc.,
- North Bay Hydro Distribution Limited,
- Waterloo North Hydro Inc.,
- Westario Power Inc.

The criteria used to determine the peer LDCs is based on total customers, Rural versus Urban Service Area, Overhead versus Underground. The comparison is shown below in Table Staff IRR – 10 – 2019 Yearbook Comparisons.

Table Staff IRR – 10 – 2019 Yearbook Comparisons

General Statistics For the Year Ended December 31	HHHI	Canadian Niagara Power Inc.	Festival Hydro Inc.	Innpower Corporation	Milton Hydro Distribution Inc.	North Bay Hydro Distribution Limited	Waterloo North Hydro Inc.	Westario Power Inc.
Total Customers	22,528	29,455	21,382	18,632	40,388	24,199	57,855	23,774
Total Customer Variance		6,927	(1,146)	(3,896)	17,860	1,671	35,327	1,246
Rural Service Area (sq km)	255	284	0	215	312	279	618	64
Urban Service Area (sq km)	26	73	43	77	56	51	65	0
Total Service Area (sq km)	281	357	43	292	368	330	683	64
Rural Service Area Variance		29	(255)	(40)	57	24	363	(191)
Urban Service Area Variance		47	17	51	30	25	39	(26)
Rural to Urban Ratio	10	4	0	3	6	5	10	0
Rural to Urban Ratio Variance		(6)	(10)	(7)	(4)	(4)	(0)	0
Total Service Area Variance		76	(238)	11	87	49	402	(217)
Overhead Circuit km of Line	932	1,488	165	837	769	494	1,072	393
Underground Circuit km of Line	754	114	96	618	1,954	79	576	167
Total Circuit km of Line	1,686	1,602	261	1,455	2,723	573	1,648	560
% Overhead to Underground	1	13	2	1	0	6	2	2
% Overhead to Underground Variance		12	0	0	(1)	5	1	1
Overhead Circuit km of Line Variance		556	(767)	(95)	(163)	(438)	140	(539)
Underground Circuit km of Line Variance		(640)	(658)	(136)	1,200	(675)	(178)	(587)
Total Circuit km of Line Variance		(84)	(1,425)	(231)	1,037	(1,113)	(38)	(1,126)
Winter Peak (kW)	83,054	78,312	99,067	54,784	145,493	99,886	240,428	80,824
Summer Peak (kW)	99,439	92,987	103,142	59,938	169,704	80,442	271,173	70,762
Average Peak (kW)	81,867	74,399	94,289	46,996	139,177	78,314	228,082	66,918
Average Peak (kW) variance		(7,468)	12,422	(34,871)	57,310	(3,553)	146,215	(14,949)
Full-time Equivalent Number of Employees	51	88	41	49	52	45	122	39
FTE Variance		37	(10)	(2)	1	(6)	71	(12)
# of Customers per square km of Service Area	80	83	492	64	110	73	85	292
# of Customers per km of Line	13	18	82	13	15	42	35	48
# Customers per square km Variance		2	412	(16)	30	(7)	5	212
# Customer per km of Line Variance		18	82	13	15	42	35	48
OM&A per Customer ($)	285	348	286	312	250	281	259	294
OM&A per customer variance		63	1	27	(35)	(3)	(26)	9
Net Income (Loss) Per Customer ($)	(16)	96	91	142	49	88	109	57
Net PP&E per Customer ($)	4,681	3,942	2,655	3,040	2,761	2,999	4,280	1,383
Net PP&E per Custoner Variance		(739)	(2,026)	(1,641)	(1,920)	(1,683)	(401)	(3,299)
Gross Capital Additions for the Year ($)	30,952,185	15,443,000	3,482,951	8,585,117	11,765,970	7,098,154	19,651,071	3,771,953
High Voltage Capital Additions for the Year ($)	23,494,533	0	0	0	0	0	184,374	0

As seen on the OM&A per Customer ($) line and OM&A per customer variance lines, three (3) of the seven (7) (Festival Hydro Inc., North Bay Hydro Distribution Limited and Westario Power Inc.) were within +/- $10 of HHHI's OM&A per customer. As such, this response with address those LDCs whose OM&A per customer is outside the+/- $10 threshold.

LDCs whose OM&A per customer is <u>less</u> than HHHI (Milton Hydro Inc. and Waterloo North Hydro Inc.):

Milton Hydro Inc. shows an OM&A per customer of $249.63 or $35.17 less per customer than HHHI's $284.79. This variance can be attributed to greater number of customers per square kilometer of service area, a smaller ratio of rural to urban service area and a much smaller overhead to underground circuit km of lines.

Waterloo North Hydro Inc. shows an OM&A per customer of $258.57 or $26.22 less than HHHI. This variance can be attributed to greater number of customers per square kilometer of service area and a smaller ratio of rural to urban service. However, as per Waterloo North interrogatory responses in proceeding EB-2020-0059, Waterloo North is projecting a 2021 OM&A per customer of $277.

LDCs whose OM&A per customer is <u>more</u> than HHHI (Canadian Niagara Power Inc. and Innpower Corporation):

Canadian Niagara Power Inc. shows an OM&A per customer of $347.75 or $62.96 greater per customer than HHHI. This variance can be attributed to a much larger ratio of overhead versus underground circuit kilometers of line and a greater number of full-time equivalent number of employees.

Innpower Corporation shows an OM&A per customer of $312.27 or $27.47 greater that HHHI's OM&A per customer. This variance can be attributed to lower number of customers per circuit km of line when compared to HHHI.

Climate Change Plan

4 - Staff IRR - 52

4-Staff-52
Ref: Exhibit 4, pp. 32-35

Preamble:

HHHI has created a climate change budget to support low carbon initiatives and activities. A total proposed OM&A budget of $279,700 is requested, broken down into five categories in Table 15 as follows:

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**

Question(s):

a) OEB staff understands that the Town of Halton Hills developed its 2020-2025 Corporate Energy Plan in July 2019.[5] Did HHHI develop its own Climate Change Plan? If so, please provide a copy. If not, please provide all relevant documents supporting HHHI's Climate Change Plan.

b) Please confirm that all OM&A amounts in the Climate Change Plan relate to the implementation of the Town of Halton Hill's Corporate Energy Plan.

c) Please confirm the proposed budgets were developed in consultation with the Town of Halton Hills and are consistent with their expectations.

d) Please clarify whether there is any capital budget included in the proposed capital expenditures relate to HHHI's Climate Change Plan.

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[5] Accessible online: https://www.haltonhills.ca/en/residents/resources/Documents/Town-of-Halton-Hills-2020-2025-Corporate-Energy-Plan.pdf

e) For the 'Supporting Low-Carbon Mobility' budget ($66,700), it includes nine potential EV charging locations that were based on a draft policy of the Town of Halton Hills.
   i. Please provide an update on whether this draft policy has been finalized. If yes, please confirm if there are any changes to the proposed locations.
   ii. Please provide the Town of Halton Hills' total Low-Carbon Mobility budget.
   iii. Please explain how the proposed budget of $66,700 will assist with the installation of EV charging facilities. Please also provide a breakdown of the activities that this budget will support. For example, will the proposed budget be used to fund evaluation studies at any EV charging locations that have not been finalized to proceed?
   iv. HHHI noted that "Through its affiliate companies, HHHI has already supported the installation of EV charging stations at the Acton Arena and Mold-Masters SportsPlex as well as two (2) charging stations at the HHHI Administration Building". Please explain why activities to assist the installation of these new charging stations cannot continually being done by HHHI's affiliate companies.

f) For the 'Preparing for EV Charging Impacts' budget ($80,000), HHHI states that it will conduct feeder impact assessments on three distribution feeders.
   i. Has HHHI done any analysis to predict EV load within its own distribution system over the 2021-2025 period? If so, please provide results of the analysis.
   ii. Which feeders (and their locations) have been identified for review, how were the feeders identified and what are the associated timelines to conduct the impact assessments?
   iii. Please provide a breakdown of the specific areas of interest that will be reviewed in the feeder impact assessments.

g) HHHI requests a budget of $60,000 to assist the Town of Halton Hills in promoting the Home Retrofit Acceleration Program.
   i. Please discuss what this program is about:
      - Please clarify whether Home Retrofit Acceleration Program is a pilot program, or a new program that has been approved by the IESO.
      - Does this program originate from the delivery of local utility programs after the CFF-wind down framework?
   ii. Please provide a breakdown of the proposed $60,000 budget, including program delivery costs, funding for new position(s) including the number of utility FTE(s) or third party contractor, and/or administration expenses, where available.
   iii. Please clarify whether HHHI is seeking OM&A funding to deliver Home Retrofit Acceleration Program, and the appropriateness of doing so. As noted in section 2.4.6 of the Filing Requirements, recovering CDM program delivery

costs (including staff labour to such dedicated programs) should not be included in revenue requirement.

h) Please confirm whether the Town of Halton Hills has indicated the need for a Climate Change Coordinator position and whether it has already employed a similar role.
   i. Please discuss the objectives and responsibilities of this new position.
   ii. Please confirm that this new position is dedicated entirely towards the initiatives set by the Town of Halton Hills. If this position will also assist with other utility tasks, please discuss.

i) Please confirm that $20,000 is requested to provide research money to McMaster University on the Integrated Community Energy Harvesting System demonstration project, which has received approval by the university to proceed.
   i. Please discuss the direct benefits that HHHI has received from this research, and the incremental benefits that the utility plans to receive from the continuation of this research.

Response:

a) HHHI's Climate Change Plan is provided as Appendix Staff IRR - B.

b) The HHHI climate Change Plan includes OM&A amounts in support of the Town's initiatives as well as funding for a distribution feeder impact assessment and funding for the McMaster University Integrated Community Energy (ICE) Harvesting System demonstration and research project which integrates CHP with thermal energy storage and microgrid technologies.

c) Confirmed.

d) All expenditures are a part of the OM&A budget and there are no proposed capital expenditures at this time.

e) Potential EV charging locations.
   i. The current list of proposed locations is as follows:

Description	Address
Public Use	
Edith St Parking lot	60 Edith St
Georgetown Fairgrounds	1 Park Ave
Willow St Parking lot	14 Willow St N
Halton Hills Fire Department HQ	14007 10th Side Rd
Acton Fire Station	21 Churchill Rd S
Dominion Gardens Park	118 Guelph St
Robert C Austin Operations Centre	11620 Trafalgar Rd
Employee Use	
Town of Halton Hills Town Hall	1 Halton Hills Dr

ii. HHHI and the Town are planning on matching funds on this initiative.

iii. Final details of the use of the budget have yet to be determined. However, it may be used to contribute to the annual maintenance of the facilities and towards studies into other locations to expand the Town's EV charging network.

iv. HHHI understands the importance of enabling customer choice and facilitating a transition to low carbon mobility options. As an innovative, environmentally conscious utility, HHHI is collaborating with the Town of Halton Hills to facilitate their EV Charging Policy.

f) Preparing for EV Charging Impacts

i. HHHI has not completed an analysis at this time. However, it is anticipated that there may be some intensification of EV charging station locations as new developments, including Vision Georgetown, move forward.

ii. Specific feeders to be targeted will be determined as part of the scope of this project.

iii. The goal of the study is to assess the level of EV penetration at which the selected feeders would begin experiencing technical operational challenges such as reduced power quality. This study will help with long term planning for the utility.

g) Promoting the Home Retrofit Acceleration Program

i. The program is currently under development. The Town of Halton Hills is working with a consultant to develop a business case and a detailed program design.

The program plans to start as a pilot eventually expanding to a full-scale program (with a future administrative model yet to be determined). After finalizing the business case report the program design will evolve through the following steps:

- *Workshop*. The purpose of the first workshop will be to present a summary of findings from the background review, energy model and economic analysis, and the preliminary program concept.
- *Draft Program Design*. The program design report will set out all major program components including participant and measure eligibility, financing terms, program theory logic model, applicant requirements, program administration and implementation, etc.
- *Finalize Program Design*. Based on feedback from staff, supplemented with targeted interviews, HHHI will update and deliver the final program design report.

ii. A detailed breakdown of the proposed budget will be developed during the pilot phase of the program.

iii. Yes, this program is OM&A. These costs are in support of a program to be delivered by the Town of Halton Hills.

h) Climate Change Coordinator position

i. This is a cost sharing position. It is yet to be determined whether the individual would be an employee of HHHI or the Town.

ii. This is a cost shared position. It is yet to be determined whether the individual would be an employee of HHHI or the Town of Halton Hills.

i) Integrated Community Energy Harvesting System demonstration project

i. Funding for this program assists HHHI in planning for carbon neutral development within Halton Hills. This program studies opportunities to combine micro grids with combined heat and power systems to reduce reliance on fossil fuels and provide energy through heat energy which would otherwise be wasted.

This program is in collaboration with the GridSmart City collaborative. See the 'Ice Harvest project' document found on the GridSmart City website https://www.gridsmartcity.com/partners-in-motion/innovation/mcmaster-ice/ .

Cyber Security

4 - Staff IRR - 53

4-Staff-53
Ref: Exhibit 4, pp. 35-37

Preamble:

HHHI budgeted $212,441 for Cyber Security.

Question(s):

a) Please provide a breakdown of historical (2018-2019), bridge (2020), and forecast (2021) cyber security costs by programs (Managed Detection & Response, Demilitarized Zone (DMZ) – Web Server & Mail Gateway, and Storage Area Network (SAN) Replacement).

Response:

a) Please note for clarification purposes, HHHI did not budget $212,441 for Cyber Security as referenced in the preamble; but rather the $212,441 is the accumulative 'cost driver' for the period 2016 through to 2021. Please see Table Staff IRR – 11 for a breakdown of cyber security costs by program and year.

Table Staff IRR – 11 – Cybersecurity Costs

Cyber Security by Programs	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Bridge Year Budget 2020	Test Year Budget 2021	Accumulative 2016 thru 2021
Managed Detection & Response	$ -	$ -	$ 930	$ 21,136	$ 53,893	$ 70,300	$ 146,259
Demilitarized Zone - Web Server & Mail Gateway	-	-	4,582	7,530	17,400	21,000	50,512
Storage Area Network	-	-	7,630	8,039	-	-	15,669
Total	**$ -**	**$ -**	**13,142**	**$ 36,705**	**$ 71,293**	**$ 91,300**	**$ 212,441**

Incremental OM&A Costs for the New Municipal Transformer Station

4 - Staff IR - 54

4-Staff-54
Ref: Exhibit 4, pp. 37-38

Preamble:

OEB staff notes that incremental OM&A costs associated with the new MTS were projected as $120,250 for 2019 and $131,515 for 2020 in the ICM application.[6]

Question(s):

a) Please provide a breakdown of incremental OM&A costs projected in the ICM application by items listed in Table 17, page 38 of Exhibit 4 for 2019 ($120,250) and 2020 ($131,515). Please explain drivers for the increase in OM&A from what projected in the ICM application ($131,515) to the current Application ($190,352).

Response:

a) Please see Table Staff IRR – 12 - Incremental OM&A Cost.

[6] EB-2018-0328, ICM Application, December 3, 2018, page 18.

Table Staff IRR – 12 – Incremental OM&A Cost

	ICM EB-2018-0328	COS EB-2020-0026	ICM EB-2018-0328	COS EB-2020-0026	COS EB-2020-0026
Cost Drivers	**April 2019 to December 31, 2019**	**November 2019 to December 31, 2019**	**January 01, 2020 to December 31, 2020**	**Bridge Year 2020**	**Test Year 2021**
Control Room and Station Maintenance - Control Room	18,750		25,000	43,050	50,000
Control Room and Station Maintenance - Station Mtce	20,000		40,000	30,000	40,000
Total Control Room	**38,750**	**-**	**65,000**	**73,050**	**90,000**
Expendable Materials - materials			-	800	800
Expendable Materials - small tools			-	500	500
Total Expendable Materials	**-**	**-**	**-**	**1,300**	**1,300**
Fibre Cable, Internet, Phone Line and Security - Fibre	3,750	1,086	5,000	10,800	10,980
Fibre Cable, Internet, Phone Line and Security - Security				5,500	5,550
Total Communication	**3,750**	**1,086**	**5,000**	**16,300**	**16,530**
Property Tax	27,750		38,110	43,030	44,321
Snow Removal			-	4,000	4,000
Building Maintenance			-	1,000	1,000
Property Insurance	15,000		18,405	-	32,115
Training Costs	35,000		5,000	-	-
Total - Other	**77,750**	**-**	**61,515**	**48,030**	**81,436**
TOTAL	**120,250**	**1,086**	**131,515**	**138,680**	**189,266**

The cost drivers for the increase of $57,751 in OM&A from the amount projected in the ICM application ($131,515) to the current Application ($189,266) include:

- Control Room costs +$25,000
- Expendable materials +$ 1,300
- Fibre, Internet & Security +$11,530
- Property taxes +$ 6,211
- Snow removal & bldg mtce +$ 5,000
- Property Insurance +$13,710
- LESS Training costs - $ 5,000

2021 Test Year vs. 2019 Actual

4 - Staff IRR - 55

4-Staff-55
Ref: Exhibit 4, pp. 43-44

Preamble:

HHHI identified reasons for the increase in distribution OM&A between 2021 test year and 2019 actuals, including the portion of labor costs allocated to OM&A versus capital and increase in vegetation management costs.

Question(s):

a) HHHI stated that it will strategically focus on maintenance mode as opposed to historical level of capital expenditures. As a result, the 2021 test year OM&A labour/burden allocation increased to 30% OM&A/70% capital from 20% OM&A/80% capital. Please explain the basis of this strategy.

b) Please provide historical (2016-2019) and forecast (2020-2021) spending on vegetation management.

Response:

a) HHHI's capital expenditure in 2021 Test Year through to 2025 will average $5.28 million annually, down significantly from historical years.

b) Please see Table Staff IRR – 13 – Vegetation Management Costs

Table Staff IRR – 13 – Vegetation Management Costs

Year	Amount
2016	$ 412,329
2017	$ 230,500
2018	$ 236,941
2019	$ 202,741
Bridge Year 2020	$ 275,000
Test Year 2021	$ 300,000

Compensation

4 - Staff IRR - 56

4-Staff-56
Ref: Exhibit 4, pp. 47-50

Question(s):

a) HHHI stated that "HHHI's total compensation program is reviewed and analyzed for its competitiveness against three (3) market comparators". Please provide results of this analysis (e.g. What's HHHI's rank among the market comparators?)

b) HHHI noted that "In setting its total compensation, HHHI uses the 50th percentile against the public and private sectors, with a primary focus on maintaining a 50th percentile position against its LDC market competition". Please explain why it is reasonable to use the 50th percentile as the target in setting HHHI's total compensation.

c) HHHI provided the annual average wage increase for non-union/management employees (Exhibit 4, page 49, Table 22). Please provide the minimum and maximum wage increase for non-union/management employees over the historical (2016-2019) and forecast (2020-2021) periods.

d) Please provide a revised version of Appendix 2-K, Employee Costs, to reflect requests as follows:

A breakdown of management positions by executives and non-executive positions.
A breakdown of non-management employees by union and non-union.
To show the expensed and capitalized compensation costs for historical (2016-2019), bridge (2020), and the test year (2021).

Response:

a) HHHI falls into the 50th percentile within the LDC sector and broader sector within Ontario.

b) Jobs within the GTA are very desirable and the talent pool is generally diverse, with many living outside of Toronto/Peel Region looking to work closer to home without a long and expensive commute. This reduces the cost of living for many and lifestyle is valued more greatly as the next generations move into their professions. The Cost Of Living is lower than within Toronto and much of the GTA. Employees are placing greater importance on non-salary compensation, such as defined benefit (DB) pension and Health & Dental Benefits. DB pensions are rare outside of the municipal and private sector. HHHI wants to maintain its competitiveness within the LDC sector and attract new and diverse talent from outside the LDC sector. To lag the market would reduce that goal, and to lead the market is unnecessary. A healthy balance of retention and turnover is necessary and will not happen with leading or lagging the market.

c) All employees received 2%.

d) The following is a breakdown of Management positions:

   a. Executives:
      i. President & CEO
      ii. CFO
   b. Non-executives:
      i. Controller
      ii. Senior Accountant
      iii. Regulatory Affairs Officer
      iv. Human Resources Manager
      v. Executive Assistant/HR
      vi. Customer Care Supervisor
      vii. IT Supervisor
      viii. Engineering Supervisor
      ix. Operations Manager
      x. Operations Supervisor
      xi. Project Manager

   c. All remaining positions are unionised:
      i. Line section
         1. Foreman
         2. Sub Foreman
         3. Powerline Technician – Journeyperson
         4. Powerline Technician – Apprentice
      ii. Engineering section:
         1. Engineering Clerk
         2. Engineering Technician
         3. Senior Engineering Technician
         4. GIS
      iii. Systems Support Section
         1. Locates/Layout Person
         2. Meter Technician
         3. Substation Technician
         4. Mechanic
         5. Stores/Buyer
         6. Information Systems Analyst
      iv. Customer Care Department
         1. Cashier
         2. Customer Service Representative

3. Billing Representative
4. Billing Coordinator

v. Finance Department

1. Accounting Coordinator
2. Payroll Clerk
3. Accounts Payable Clerk

Please see Table Staff IRR – 14 for the revised Appendix 2-K.

Table Staff IRR – 14 - Revised Appendix 2-K.

	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management - Executive	2	2	2	2	2	2
Management - Non Executive	10	10	11	11	11	11
Non-Management - Union	41	40	36	37	40	43
Total	**53**	**52**	**49**	**50**	**53**	**56**
Compensation Expensed						
Management and Union	$ 3,617,135	$ 3,886,774	$ 3,927,562	$ 3,944,441	$3,868,410	$ 4,432,167
Total	**$ 3,617,135**	**$ 3,886,774**	**$ 3,927,562**	**$ 3,944,441**	**$3,868,410**	**$ 4,432,167**
Compensation Capitalized						
Management and Union	$ 1,991,179	$ 1,838,817	$ 1,815,384	$ 1,975,078	$2,251,445	$ 2,187,920
Total	**$ 1,991,179**	**$ 1,838,817**	**$ 1,815,384**	**$ 1,975,078**	**$2,251,445**	**$ 2,187,920**
Total Compensation (Salary, Wages, & Benefits)						
Management - Executive						
Management - Including Executive	$ 1,815,909	$ 1,888,740	$ 1,941,828	$ 2,146,383	$2,066,893	$ 2,166,181
Non-Management - Union	$ 3,792,405	$ 3,836,851	$ 3,801,118	$ 3,773,136	$4,052,962	$ 4,453,907
Total	**$ 5,608,314**	**$ 5,725,591**	**$ 5,742,946**	**$ 5,919,519**	**$6,119,855**	**$ 6,620,087**

Shared Services and Corporate Cost Allocation

4 - Staff IRR - 57

4-Staff-57
Ref: Exhibit 4, pp. 65-73

Preamble:

For the 2021 test year HHHI forecasted $413.9k for services provided by HHHI to parent and affiliate companies, and $248.1k for services purchased from parent and affiliate companies.

Question(s):

a) For services HHHI purchases from affiliate companies with a pricing methodology of "Cost plus mark up".
   i. Please specify the percentage of mark up for each service (Electrical Contracting Services and Smart Meter Repairs, and Arborist and Tree Trimming Services).
   ii. Please explain the basis of setting the mark up for each service.

b) It was noted that no amounts have been included for the 2021 test for two services provided to HHHI because the information was not available at the time of filing the Application. Will HHHI update the 2021 services purchased from affiliate companies once the information becomes available?

Response:

a) Cost plus mark up
   i. The percentage of mark-up for services relating to electrical contracting, smart meter repairs and arborist and tree trimming services is not public information and forms part of the proprietary information belonging to the respective non-regulated affiliate corporations.

   ii. The basis of setting the mark-up for each service is competitive market pricing.

b) HHHI does not intend to update the 2021 services purchased from affiliate companies.

LRAMVA

4 - Staff IRR - 58

4-Staff-58
Ref: LRAMVA workform, Tabs 5 and 8
LRAMVA, Tab "Streetlight Details"

Preamble:

HHHI did not confirm it received reports from the Town of Halton Hills to validate the number and type of bulbs replaced/retrofitted through the IESO program. OEB staff also has other clarification questions regarding the calculation of street lighting savings.

Question(s):

a) Please confirm that HHI received reports from the Town of Halton Hills to validate the number and type of bulbs replaced/retrofitted through the IESO program. If not, please discuss the source of the data and validation process to confirm the number and type of bulbs changed.

b) Please confirm whether the energy savings related to street lighting upgrades (2015, 2016 and 2017) have been deducted from the respective saveOnEnergy business retrofit programs in Tab 5.

   i. If not, please quantify the energy savings related to street lighting upgrades from the 2015, 2016 and 2017 saveOnEnergy business retrofit programs. Please revise Tab 5 of the LRAMVA workform as appropriate.

c) In Tab 8, there is a note at row 111 of this spreadsheet indicating: "incremental street light savings removed".

   i. Please confirm that the street light savings do not include savings due to natural replacements that were done outside of the saveOnEnergy CDM program.
   ii. Please confirm that the savings not attributable to the IESO program have been removed from the analysis.

d) In Tab 8, please confirm that the billed kW amounts for all projects (column B) represent the level of demand from new LED replacements occurring each month in the year that are incremental from the previous month.

   i. Please discuss the appropriateness of calculating 2015 persisting savings into 2016, 2017 and 2018 using gross kW savings (column D). Please update the savings persistence calculation using net kW reductions (column G) in 2015.

ii. Please discuss the appropriateness of calculating 2016 persisting savings into 2017 and 2018 using gross kW savings (column D). Please update the savings persistence calculation using net kW reductions (column G) in 2016.

Response:

a) Confirmed. Please see Appendix Staff IRR – C.

b) Please see the revised LRAMVA Workform filed as Halton_IRR_4-Staff-58b_LRAMVA_20201125.

c) Incremental streetlight savings removed
   i. Confirmed.

   ii. Confirmed.

d) Billed kW amounts for all projects
   i. Persistence values have been revised to account for the Net to Gross ratio. This adjustment is made by combining Columns D and E as column G would inappropriately discount savings according to the month of the replacement.

   ii. Please see HHHI's response to 4 – Staff IRR – 58 part d (i).

4 -Staff IRR- 59

4-Staff-59
Ref: LRAMVA Workform, Tab 1-a

Question(s):

a) If HHHI made any changes to the LRAMVA workform as a result of its responses to the above LRAMVA interrogatories, please file an updated LRAMVA workform, and confirm the LRAMVA balance requested for disposition, the disposition period and the revised rate riders.

b) Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 1-a)".

c) If there is any supporting documentation filed in response to the above interrogatories, please ensure that all confidential information that may be filed be removed or treated in accordance with Rule 9A of the OEB's *Rules of Practice and Procedure*.

Response:

a) An updated LRAMVA workform is filed as Halton_IRR_4-Staff-58b_LRAMVA_20201125. The revised LRAMVA balance requested for disposition is $345,193.00, including carrying charges to April 30, 2021. The claim has decreased due to the decline in Street Light kW persistence with the application of the net-to-gross ratio and removal of energy savings related to Street Lights in Tab 5. This reduction is mostly offset with the addition of unverified 2016 and 2017 from the April 2019 Participation and Cost report.

Table Staff IRR – 15 - Revised LRAMVA Values

Rate Class	Billing Unit	Principal	Carrying Charges	Total LRAMVA	Load Forecast	Proposed Rate Rider
Residential	kWh	163,401	10,299	173,700	20,852	0.3471
General Service less than 50 kW	kWh	107,492	6,970	114,462	46,722,885	0.0012
General Service 50 to 999 kW	kW	36,556	2,558	39,114	371,084	0.0527
General Service 1,000 to 4,999 kW	kW	28,665	1,954	30,619	168,373	0.0909
Unmetered Scattered Load	kWh	0	0	0	962,029	0.0000
Sentinel Lights	kW	0	0	0	680	0.0000
Street Lighting	kW	(11,828)	(874)	(12,702)	3,105	2.0455
Total		**324,286**	**20,907**	**345,193**		

HHHI proposes to recover the LRAMVA balance over a two (2) year period, consistent with its original proposed recovery period.

b) All changes are described in Table A-2 of the updated workform.

c) No additional supporting documentation is filed in response to the above interrogatories.

4 - Staff IRR - 60

4-Staff-60
Ref: Exhibit, pages 61-63

Preamble:

HHHI forecasted $1,087,739 in post-employment benefits in 2021, which is to be recorded on an actuarial valuation basis. HHHI explains that:

> The annual expense, realization of any gain/(loss) and liability are determined in accordance with IFRS Standards-Employee Benefits IAS 19 and supported by an actuarial valuation, completed every three years. The current actuarial valuation is for the period ended December 31, 2019.

OEB staff notes that the 2019 actual post-employment expense is $940,115, which is based on the actuarial report for the post-retirement liability as at December 31, 2019.

	IAS 19	IAS 19	IAS 19	IAS 19	IAS 19	IAS 19
	31-Dec-2016	31-Dec-2017	31-Dec-2018	31-Dec-2019	31-Dec-2020	31-Dec-2021
Accrued benefit liability	763,169	902,827	922,998	940,115	1,078,958	1,087,739

Question(s):

a) Please explain how HHHI extrapolates the 2019 results for 2020 and 2021.

b) Given the current low interest rate environment arising from the COVID-19 pandemic, please explain whether the extrapolation mentioned above should be revised to recognize that discount rates in 2019 are potentially no longer representative of those expected in future years?
    i. If so, please provide a revised 2021 extrapolated result.
    ii. If not, why not.

Response:

a) Please refer to Table 30 in Exhibit 4, page 62. The 2019 actual post-employment expense is $17,117, not $940,115. The accrued benefit liability at December 31, 2019 is $940,115, which is based on the actuarial report for the post-retirement liability as at December 31, 2019.

   The 2020 Bridge Year post-employment forecast expense is $138,843 consisting of an actuarial loss of $131,561 plus post-employment expense of $7,282. The resulting accrued benefit liability forecast to December 31, 2020 is $1,078,958.
   The 2021 Test year post-employment forecast expense is $8,781. The resulting accrued benefit liability forecast to December 31, 2021 is $1,086,739.

b) Is a revision required

i. HHHI engaged RSM Canada Consulting LP to estimate the benefit expense and plan obligation on the basis of IFRS IAS 19 as on December 31, 2019 and to extrapolate the results for the 2020 Bridge Year and 2021 Test Year. The same employee data, methodology and assumptions that were used in the December 31, 2019 actuarial valuation report under IAS 19, were used for this extrapolation. RSM Canada Consulting LP stated in their correspondence that the calculations conform to the standards set out in the amendments to International Accounting Standard 19 (Employee Benefits), but **note that significant changes to the benefit costs or demographics** ***[emphasis added]*** in 2020 or 2021 would require a full actuarial review. HHHI does not anticipate significant changes therefore the December 31, 2019 information will be used in the 2021 Test Year.

   The discount rates recognized in 2019 remain valid. The current low interest rate environment is only one element in the calculating the actuarial valuation. HHHI does not support revising the actuarial calculation to recognize the current short-term interest rates.

ii. Not applicable.

Exhibit 5 – Cost of Capital

5 - Staff IR - 61

5-Staff-61

Ref: Exhibit 5/Section 5.2 Capital Structure/page 4

Preamble:

OEB staff notes different weighted average cost of capital rates in the Application. On line 4, it shows 6.02% while on line 21, it shows 5.46%.

Question(s):

a) Please clarify the weighted average cost of capital rate used in the Application used to derive the 2021 test year revenue requirement.

Response:

a) The weighted average cost of capital rate used in the Application to derive the 2021 Test Year revenue requirement is 5.46%.

5 - Staff IRR - 62

5-Staff-62
Ref: Exhibit 5/Section 5.2 Capital Structure/page 5

Preamble:

HHHI provided an overview of its capital structure in the Table below.

Table 1 - Overview of Capital Structure[3]

Particulars	2016 Cost of Capital				2021 Cost of Capital				2021 Deemed
	(%)	(%)	$		(%)	(%)	$		(%)
Debt									
Long-term Debt	56%	2.89%	$994,618		56%	3.48%	$2,029,274		4.16%
Short-term Debt	4%	1.65%	$40,539		4%	2.75%	$114,674		2.29%
Total Debt	60%	2.81%	$1,035,157		60%	3.43 %	$2,143,948		4.04%
Equity									
Common Equity	40%	9.19%	$2,257,893		40%	8.52%	$3,552,813		9.00%
Preferred Shares									
Total Equity	40%	9.19%	$2,257,893		40%	8.52%	$3,552,813		9.00%
WACC	100%	5.36%	$3,293,050		100%	5.46%	5,696,761		6.02%

OEB staff notes that cost of capital parameters summarized in Table 1 above do not reconcile with parameters provided in the RRWF, Cost of Capital tab.

Question(s):

a) For the right-most column titled "2021 Deemed", please explain the basis, and identify the source, for each of the cost of capital parameters:
   i. Long-term debt rate of 4.16%
   ii. Short-term debt rate of 2.29%
   iii. Return on equity (ROE) of 9.00%

b) Please provide a copy of Table 1, adjusted as necessary as a result of responses to interrogatories, in working Microsoft Excel format.

Response:

a) Table clarification
   i. The right-most column titled "2021 Deemed" is not applicable.

   ii. The right-most column titled "2021 Deemed" is not applicable.

iii. The right-most column titled "2021 Deemed" is not applicable.

b) The updated table is presented below as Table Staff IRR – 16 - Revised Overview of Capital Structure. The Excel version is filed as Halton_Att_5-Staff-62b_CapitalStructure_20201125.

Table Staff IRR – 16 - Revised Overview of Capital Structure

Particulars	2016 Cost of Capital				2021 Cost of Capital		
	(%)	(%)	$		(%)	(%)	$
Debt							
Long-term Debt	56%	2.89%	$994,618		56%	3.48%	$2,029,274
Short-term Debt	4%	1.65%	$40,539		4%	2.75%	$114,674
Total Debt	60%	2.81%	$1,035,157		60%	3.43%	$2,143,948
Equity							
Common Equity	40%	9.19%	$2,257,893		40%	8.52%	$3,552,813
Preferred Shares							
Total Equity	40%	9.19%	$2,257,893		40%	8.52%	$3,552,813
WACC	100%	5.36%	$3,293,050		100%	5.46%	5,696,761

5 - Staff IRR - 63

5-Staff-63
Ref: Exhibit 5/Section 5.2 Capital Structure/page 5

Preamble:

HHHI provided actual ROE performance compared to deemed ROE in the table below for the period of 2016 through 2019.

Table 2 - Actual ROE compared to Deemed ROE

	Deemed	**9.19%**	**9.19%**	**9.19%**	**9.19%**
Return on Equity	Achieved	6.76%	6.98%	7.07%	4.24%

OEB staff notes that the achieved 2019 ROE is 4.24% and is 4.95% below the deemed ROE of 9.19% (i.e. more than 300 basis points below the last approved ROE for HHHI).

HHHI submitted its 2019 ROE Form with the OEB on June 1, 2020.

Question(s):

a) Please provide more detailed drivers (e.g. OM&A programs and/or capital projects that lead to higher expenditures) of the ROE under performance.

Response:

a) The 2019 ROE of 4.24% is the result of:
   - lower energy consumption leading lower distribution revenue;
   - lower specific service charges do to the ‘disconnection moratorium’;
   - increase in interest expense
   - increase in depreciation

5 - Staff IRR - 64

5-Staff-64
Ref: Exhibit 5/Section 5.5.4 Long-Term Debt/page 14

Preamble:

On page 14, HHHI provides the following as quoted from the settlement proposal in its last rebasing application:[7]

> "HHHI agrees that prior to its next cost-of-service application, it will conduct a review of long-term debt financing options available to HHHI and will file the results of such review in its next cost-of service application."

HHHI then states that it conducted a review of its long-term debt financing options and is restructuring its long-term debt as follows:

1. Promissory Note $16,141,970
2. Interest Rate Swap #1 $23,000,000
3. Interest Rate Swap #2 $31,077,000

Question(s):

a) Is there a report summarizing the details of HHHI's review of its long-term debt financing options? If so, please file it on the record.

b) If not, please explain why a report of the debt financing is not available, and why it believes that the evidence provided in this Application satisfies the settlement agreement from the last rebasing application.

c) Please explain how HHHI conducted its review of its long-term debt. Please identify options considered. Please indicate any consultations that helped HHHI with this review.

Response:

a) Executive Management made several formal presentations to HHHI's Board of Directors with the overall strategic objective to mitigate rate risk exposure over the long-term. Effectively, the objective was to hedge interest rate exposure on Long-Term Debt, by establishing a fixed interest rate 'today' for thirty (30) years. Alternatively, a conventional loan renewing every five)5) years has an inherent interest rate risk during periods of rising interest rates.

   The presentations provided to HHHI's Board of Directors to inform their deliberations regarding approval of the financing options is not public information and forms part of the confidential Board proceedings.

[7] EB-2015-0074

b) As explained in part (a) above, the debt financing report is not available.

In HHHI's view, this Application successfully satisfies the settlement agreement on two principles:

I. HHHI's long-term debt projected to December 31, 2021 is $69,561,039 with an average interest rate of 3.476%. The actual long-term debt at December 31, 2016 was $29,220,039 with an average interest rate of $3.252%. 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 were expected to continue. HHHI suffered as a result of this volatility. 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 thirty (30) years, all of which will benefit HHIHI's Customers. This was all prior to COVID-19 pandemic.

II. The Promissory Note payable to the ultimate shareholder is being refinanced over the period through to 2025, at interest rates lower than the current 4.12% interest rate.

c) Executive Management consulted with third party experts with the objective to secure required financing for the new transformer station and monetizing the Promissory Note. Considerations were given to private placements. However, a private placement was cost prohibitive for a mid-size utility like HHHI.

HHHI ultimately worked with the TD Commercial Bank and TD Securities in securing construction financing and considerations to monetize the Promissory Note, with minimum financial covenants.

5 - Staff IRR - 65

5-Staff-65
Ref: Exhibit 5/Section 5.5.4 Long-Term Debt/page 15

Preamble:

HHHI entered into an interest rate swap agreement (Interest Rate Swap #1, a 30 year instrument) to pay a fixed rate of interest of 4.095%, exclusive of bank transaction fees, in lieu of prime rate on its capital MTS loan.

HHHI also entered into a contractual agreement (Interest Rate Swap#2) with a fixed rate of interest of 2.951% exclusive of bank transaction fees.

Question(s):

a) For each of Interest Rate Swap # 1 and Interest Rate Swap #2, please provide an estimate of the effective annual rate for Interest Rate Swap #1, inclusive of bank transaction fees.

Response:

a) Interest Rate Swap #1 rate details:
   - Start date: September 06, 2019
   - Base Rate swap 2.915%
   - Stamping fee 1.180%
   - All-in Fixed rate 4.095%
   - An indicative rate of 4.095% equates to a monthly principal and interest payment of $111,069

   Interest Rate Swap #2 rate details:
   Indicatively:
   - Start: May 25, 2021
   - End: May 25, 2051
   - Starting Notional: $31,077,000
   - Interest Rate Term: 30-years
   - Amortization: 30-years
   - Rolling 5-year loan commitment
   - Stamping Fee 118bps
   - Halton Hills Pays: **2.954% All-In**

5 - Staff IRR - 66

5-Staff-66
Ref: Exhibit 5/Section 5.5.6 Notional Debt/pp. 17-19

Preamble:

On page 17 of Exhibit 5, HHHI states that:

> As at December 31, 2019 HHHI's notional debt position is 73.5% Debt and 26.5% Equity. HHHI is forecast to remain outside the deemed 60% Debt to 40% Equity notional debt position in 2020 Bridge Year and 2021 Test Year. There is no profit or loss on redemption of debt or preferred shares.

On pages 18-19, HHHI provides a Table showing various calculations from 2016 to 2021 test year.

OEB staff note the following data on HHHI's calculated debt and equity thicknesses (percentage of total capital funded by debt or equity), shown towards the bottom of page 18.

Year	**2016**	**2017**	**2018**	**2019**	**2020 Bridge Year**	**2021 Test Year**
Debt (%)	47.1%	56.6%	77.9%	73.5%	65.5%	63.3%
Equity (%)	52.9%	43.4%	22.1%	26.5%	34.5%	36.7%

Question(s):

a) Please provide a copy of Table 8 in working Microsoft Excel format.

b) Please explain the purpose of Table 8, how HHHI has used it in preparing its application.

c) Please explain the reasons behind the swings from underleveraging in 2016 and 2017, to a material overleveraging in 2018 and 2019, with debt thickness exceeding 70% in both years.

d) Please explain the gradual movement back towards the 60% deemed debt thickness in 2020 and 2021, and how HHHI is accomplishing this.

e) HHHI negotiated new swap loan agreements in 2019, at a time when the utility was overleveraged. In HHHI's view, did its heavy debt thickness factor into the terms and rates of the swap agreements? Please explain.

Response:

a) Please see Halton_Att_5-Staff-66a_NotionalDebt_20201125.

b) With reference to EB-2015-0074 Exhibit 5, Tab 3, Schedule 4, Page 11 of 23, HHHI forecast negative notional debt for 2018 and 2019. The forecast was very accurate.

c) The construction and financing of the $23.0M transformer station was 100.0% debt.

d) The gradual movement back towards the 60% deemed debt will be accomplished as follow:
   i. Having Just and Reasonable Distribution Rates approved by the OEB.
   ii. Reducing average capital expenditure for the next five years as per the distribution system plan.

e) The heavy debt thickness factor in 2019 did not factor into the terms and rates of the swap agreements. As per Management's 2017 forecasts came to fruition as planned.

5 - Staff IRR - 67

5-Staff-67
Ref: Exhibit 5/Appendix 5-1 Promissory Note

Preamble:

It was stated that "Interest shall be payable by Halton Hills Hydro Inc. to The Corporation of the Town of Halton Hills, or assign, at a rate of interest per annum, compounded annually not in advance, prescribed, from time to time, by the Treasurer of The Corporation of the Town of Halton Hills in accordance with the provisions of By-laws No. 00-100 and 01-130 of The Corporation of the Town of Halton Hills". There is no explicit interest rate, nor detailed terms and conditions for altering the rate, documented in the Promissory Note.

Question(s):

Please provide the following:

a) Copies of By-laws 00-100 and 01-130.

b) A schedule showing all of the interest rates prescribed by the Treasurer of The Corporation of the Town of Halton Hills for the Promissory Note, and the dates at which the rate changed.

Response:

a) A copy of By-law 00-100 and 01-130 are shown in Appendix Staff – D.

b) The schedule of all the interest rates prescribed by the Treasurer of the Corporation of the Town of Halton Hills for the Promissory Note is shown in Table Staff – 17 – Town of Halton Hills Prescribed Interest Rates.

Table Staff – 17 – Town of Halton Hills Prescribed Interest Rates

Fiscal Year	Interest Rate	Effective Date
2001 - 2005	7.25%	
2006	9.16%	
2007	8.93%	
2008 - 2011	6.25%	
2012	6.25%	January 01, 2012 to April 30, 2012
	5.01%	May 01, 2012 to December 31, 2012
2013 - 2015	4.12%	
2016	4.12%	January 01,2016 to April 30, 2016
	4.54%	May 01, 2016 to December 31, 2016
2017 - 2020	4.12%	

Exhibit 7 – Cost Allocation

7 - Staff IRR - 68

7-Staff-68

Ref: Exhibit 3, page 30
Cost Allocation Model, Tab I6.2 Customer Data

Preamble:

The load forecast includes 20,852 Residential customers, and 1,876 General Service < 50 kW customers. The cost allocation model includes 20,758 Residential customers and 1,863 General Service < 50 kW customers.

Question(s):

a) Please reconcile the difference.

Response:

a) The customer numbers in the load forecast are the year ended forecasted numbers. The customer numbers reflected in the cost allocation model are the average number. Please see Table Staff IRR – 18 – Reconciled Customer Numbers below.

Table Staff IRR – 18 – Reconciled Customer Numbers

Rate Class	2020 Bridge Year	2021 Test Year	Average
Residential	20,663	20,852	20,758
General Service less than 50 kW	1,850	1,876	1,863
General Service 50 to 999 kW	219	219	219
General Service 1,000 to 4,999 kW	9	9	9
Unmetered Scattered Load	183	183	183
Sentinel Lights	175	175	175
Street Lighting	4,833	4,833	4,833

7 - Staff IRR - 69

7-Staff-69

Ref: Revenue Requirement Work Form (RRWF), Tab 4. Rate Base.
Cost Allocation Model, Tab I3 TB Data, Tab O1 Revenue to cost.
Chapter 2 Appendix 2 BA

Preamble:

The cost allocation model has an allocated rate base of $104,079,787. The Rate Base from the RRWF is $104,249,216. The cost allocation model has $7,737,808 of OM&A expenses included in the working capital calculation on sheet O1 Revenue to cost, while the RRWF uses $7,432,968 of controllable expenses in its calculation of working capital allowance.

USoA account 1606 Organization is determined by the cost allocation model to be a Non-Distribution Asset and is not included in the rate base by the cost allocation model. It is included in the rate base on Appendix 2-BA.

Question(s):

a) Please explain what HHHI has recorded in the asset 1606 Organization, and why HHHI believes it should, or should not be included in Rate Base.

b) Please reconcile the differences between the RRWF and the cost allocation model.

Response:

a) The amount recorded in asset account 1606 Organization is incorporation costs. HHHI believes that this amount should be included in rate base.

b) The difference between cost allocation and the RRWF is presented in Table Staff IRR – 19 – Reconciliation between Cost Allocation and RRWF below. The amount in the RRWF is correct and is used to calculate revenue requirement.

Table Staff IRR – 19 – Reconciliation between Cost Allocation and RRWF

	Rate Base per Cost Allocation	Rate Base per RRWF	Variance
OM&A Expenses	7,737,808	7,737,808	-
Less: Allocated Depreciation in OM&A	-	(304,840)	304,840
Total OM&A	**7,737,808**	**7,432,968**	**304,840**
Cost of Power	57,796,943	57,796,943	-
Total Working Capital	65,534,751	65,229,911	304,840
Working Capital Allowance	4,915,106	4,892,243	22,863
Average Fixed Assets	99,164,680	99,356,973	(192,293)
Rate Base	**104,079,786**	**104,249,216**	**(169,430)**

7 - Staff IRR - 70

7-Staff-70

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

Preamble:

The General Service 1,000 to 4,999 kW rate class has nine customers with 168,373 kW of forecasted demand. One customer is identified as requiring use of HHHI's line transformation. A total of 207,107 kW of demand is subject to transformer ownership allowance.

Question(s):

a) Please explain how more than the entire class load is subject to a transformer ownership allowance.

b) Please provide revisions as required.

Response:

a) Tab 16.2 customer data in the Cost Allocation model will be updated to reflect the correct transformer allowance for General Service 1,000 to 4,999 kW.

b) All changes resulting from this update are provide in the updated submitted RRWF model (Halton_IRR_2021_Rev_Reqt_Workform_20201125) in addition to the updated cost allocation model (Halton_IRR_2021_Cost_Allocation_Model_ 20201125). For reference, the revised Tab I6.1 Revenue Worksheet is shown below.

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	459,373,031
Total kWs from Load Forecast	543,241
Deficiency/sufficiency (RRWF 8. cell F51)	- 5,348,855
Miscellaneous Revenue (RRWF 5. cell F48)	1,223,382

			1	2	3	4	7	8	9
	ID	Total	Residential	GS < 50	GS 50-999 kW	GS 1000-4999 kW	Street Light	Sentinel	Unmetered Scattered Load
Billing Data									
Forecast kWh	CEN	459,373,031	207,178,634	46,722,885	132,955,988	70,322,012	979,604	251,879	962,029
Forecast kW	CDEM	543,241	-	-	371,084	168,373	3,105	680	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		263,357			107,413	155,944			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	459,373,031	207,178,634	46,722,885	132,955,988	70,322,012	979,604	251,879	962,029

7 - Staff IRR - 71

7-Staff-71
Ref 1: Cost Allocation Model, Tab I6.2 Customer Data

Preamble:

HHHI has identified that 200 of 219 General Service 50 – 999 kW customers, and one of nine General Service 1,000 to 4,999 kW customers require the use of HHHI's line transformers. However, it indicates that all customers require the use of HHHI's secondary distribution system.

All the residential and General Service under 50 kW customers are counted as requiring both line transformation and secondary distribution.

Question(s):

a) Please describe the connection arrangement where a customer is deemed to be taking secondary distribution but does not require the use of a HHHI line transformer.

b) Does HHHI have any residential customers connected directly to HHHI's primary distribution system, such as customers in a multi-unit building?

c) Does HHHI have any analogous general service < 50 kW customers directly to HHHI's primary distribution system, such as those in a multi-unit development

Response:

a) Outside of load transfers, HHHI does not have any connection arrangements where a customer is deemed to be taking secondary distribution but does not require the use of a HHHI line transformer.

b) HHHI does have residential customers connected directly to HHHI's primary distribution system including multi-unit buildings and rural agriculture.

c) HHHI does have analogous General Service less than 50 kW customers connected directly to HHHI's primary distribution system, such as those in multi-unit developments.

7 - Staff IRR - 72

7-Staff-72
Ref: Exhibit 7, page 14.
Exhibit 8, page 15.

Preamble:

HHHI states that it "proposes to maintain the revenue to cost ratios similar to what was approved in HHHI's 2016 COS (EB-2015-0074)." It states that it "helps to mitigate any large rate increases." HHHI makes specific reference to the residential rate class where it proposes to return the revenue to cost ratio to near the 2016 approved ratio of 95.09% from the cost allocation result of 105.67%. As a result, it proposes to increase the fixed charge from $27.34 / month to $37.31/ month, an increase of 36%.

In the General Service 1,000 to 4,999 kW rate class, the revenue to cost ratio is proposed to return to 120% from the cost allocation result of 71.35%. The fixed charge is proposed to increase from $192.10 / month to $510.87 / month (166%), and the variable charge is proposed to increase from $3.5931 to $8.3308 / kW (132%).

Question(s):

a) Please indicate the main drivers of the change in revenue to cost ratios from 2016 approved to the 2021 cost allocation results.

b) In reference to the changes noted in part a) please explain why the revenue to cost ratios approved in EB-2015-0074 with 2016 forecast costs and usage remain appropriate for use in 2021.

c) Please provide references to any policy instruments or past decisions which support HHHI's proposal to apply revenue to cost ratios from a previous proceeding into the current proceeding.

d) Please confirm that had no adjustments to the revenue-to-cost ratios from cost allocation been made, all rate classes would have experienced the same percentage increase to base rates or explain why this is not the case.

e) Please provide a scenario where the revenue to cost ratios as adjusted as follows:
   i. Ratios outside the boundaries from cost allocation are brought to the nearest boundary.
   ii. Any resulting over / under collection is addressed by moving ratios above / below 100% towards 100% only as required to recover the revenue requirement.

Response:

a) The main drivers for the change in the revenue to cost ratios from 2016 approved to the 2021 cost allocation results are the following:

- Change in the load forecast
- Change in expenses
- Change in utility net income

b) HHHI proposed to use the revenue to cost ratios approved in EB-2015-0074 with 2016 forecast costs and usage for 2021 in order the mitigate the large increase in rates for the residential rate class had HHHI used the 2021 revenue to cost ratios and load forecast. Residential customer rates is now a 100% fixed compare to 2016 where residential was 66.5% fixed.

c) HHHI is not aware of any policy instruments or past decisions which support HHHI's proposal to apply revenue to cost ratios from a previous proceeding into the current proceeding. HHHI proposed this approach in order to mitigate the rate increase for residential customers.

d) HHHI can confirm that, had no adjustments to the revenue to cost ratios from cost allocation been made, all rate classes would have experienced the same percentage increase to base rates. However, HHHI notes that in the case mentioned above, the revenue to cost ratios for the following classes would be outside on the OEB policy range for revenue to cost ratios:
    - General Service 1,000 to 4,999 kW
    - Sentinel Lights
    - Street Lighting
    - Unmetered Scattered Load

e) Revenue to Cost Ratio Scenarios
    i. Below is a summary of the result of moving the revenue to cost ratios to the nearest boundary.

Result from OEB Staff 72 - e

Class	Revenue Requirement - 2021 Cost Allocation Model - Line 40 from O1 in CA	2021 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2021 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2021 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	10,644,454	10,384,837	863,681	11,248,518	105.7%	105.67%	105.675%	11,248,517	863,681	10,384,836	85%	115%
GS < 50 kW	1,684,188	1,756,958	121,606	1,878,564	111.5%	111.54%	109.697%	1,847,500	121,606	1,725,894	80%	120%
GS >50 to 999 kW	3,246,944	2,522,152	184,495	2,706,648	83.4%	83.36%	83.360%	2,706,648	184,495	2,522,153	80%	120%
GS >1000 to 4999 kW	1,169,371	764,687	69,649	834,335	71.3%	71.35%	80.000%	935,497	69,649	865,848	80%	120%
Sentinels	55,226	69,914	4,727	74,640	135.2%	135.15%	109.697%	60,582	4,727	55,855	85%	120%
Street Lighting	170,312	218,093	42,848	260,941	153.2%	153.21%	109.697%	186,826	42,848	143,978	70%	120%
Unmetered and Scattered	75,371	35,842	6,377	42,219	56.0%	56.02%	80.000%	60,297	6,377	53,920	80%	120%
TOTAL	**17,045,865**	**15,752,482**	**1,293,383**	**17,045,865**				**17,045,866**	**1,293,383**	**15,752,484**		

    ii. Below is a summary of the result of moving the revenue to cost ratios by moving any over / under collection that are above / below 100% only as required to recover the revenue requirement.

As proposed by HHHI													
Class	Revenue Requirement - 2021 Cost Allocation Model - Line 40 from O1 in CA	2021 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2021 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2021 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	10,644,454	10,384,837	863,681	11,248,518	105.7%	105.67%	95.412%	10,156,068	863,681	9,292,387	85%	115%
GS < 50 kW	1,684,188	1,756,958	121,606	1,878,564	111.5%	111.54%	120.000%	2,021,025	121,606	1,899,419	80%	120%
GS >50 to 999 kW	3,246,944	2,522,152	184,495	2,706,648	83.4%	83.36%	96.600%	3,136,547	184,495	2,952,052	80%	120%
GS >1000 to 4999 kW	1,169,371	764,687	69,649	834,335	71.3%	71.35%	120.000%	1,403,245	69,649	1,333,596	80%	120%
Sentinels	55,226	69,914	4,727	74,640	135.2%	135.15%	95.412%	52,692	4,727	47,966	85%	120%
Street Lighting	170,312	218,093	42,848	260,941	153.2%	153.21%	120.000%	204,374	42,848	161,526	70%	120%
Unmetered and Scattered	75,371	35,842	6,377	42,219	56.0%	56.02%	95.412%	71,913	6,377	65,536	80%	120%
TOTAL	17,045,865	15,752,482	1,293,383	17,045,865				17,045,866	1,293,383	15,752,484		

7 - Staff IRR - 73

7-Staff-73
Ref: Chapter 2 Appendix 2-Q

Preamble:

HHHI Hydro has entered $0 associated with Distribution Stations, Low Voltage (LV) Line, and LV Line #2.

Question(s):

a) Please indicate the rationale behind the assignment of $0 of OM&A to these assets.

b) Has HHHI considered any means of allocating its OM&A for maintaining and operating distribution stations, and low voltage lines to these assets, and if so, please provide the required details to perform a calculation.

c) Please provide the total OM&A associated with maintaining and operating distribution stations, and low voltage lines.

d) Please provide total km of and total kVA of distribution lines in HHHI's service territory. If exact values are not readily known, please provide estimates, and describe the means used to create the estimates.

Response:

a) HHHI does not track OM&A costs by specific asset location, thus, it was not possible to determine specific OM&A costs.

b) As HHHI has not had a previous Embedded Distributor class, it has not considered any means of allocating its OM&A for maintaining and operating distribution stations, and low voltage lines to these assets.

c) As per HHHI's 2019 OEB RRR Trial Balance, the total OM&A costs associated with maintaining and operating distribution stations and low voltage lines is $1,072,844.

d) As per HHHI's 2019 OEB RRR reporting, the total km of lines is shown below in Table Staff IRR – 20 – HHHI Total Circuit km of Line

Table Staff IRR – 20 – HHHI Total Circuit km of Line

Description of Line	Circuit km of Line
Primary Overhead	637
Primary Underground	266
Secondary Overhead	295
Secondary Underground	488
Total Circuit km of Line	**1,686**

With respect to the total kVa,

- The total nameplate kVA of all Municipal Stations owned by HHHI is 101,500 kVA. The total nameplate kVA of all Municipal Transformer stations (HHHI MTS # 1) is 113,000 kVa.
- The nameplate kVA of the station used to provide service to the embedded distributor is 5,000 kVA.
- The annual demand on the station expressed as the sum of 12 monthly peaks is 26,752 kW.
- The annual billed kW/kVA to the embedded distributor is 12,440 kW.

Exhibit 8 – Rate Design

Specific Service Charges

8 - Staff IRR - 74

8-Staff-74

Ref: Exhibit 8/Section 8.2.8 Specific Service Charges

Preamble:

HHHI does not propose changes to its retail and specific service charges in the Application with the exception of the wireline pole attachment charge, which will be updated per OEB's decision.

Question(s):

a) Please confirm retail service charges listed in Table 13 (Exhibit 8, page 22) reflect the OEB's generic retail service charges.

b) Please confirm HHHI proposes to update its retail service charges and the wireline pole attachment charge annually per the OEB's decisions.

c) Please confirm HHHI proposes to maintain its specific service charges (except the pole attachment charge) at the 2020 approved levels for the 2021-2025 rate period.

Response:

a) Confirmed.

b) Confirmed.

c) Confirmed, unless the OEB issues any additional decisions or guidelines.

Rate Design

8 - Staff IRR - 75

8-Staff-75
Ref: Exhibit 8, page 13.

Preamble:

The General Service < 50 kW rate class has a fixed charge that is already above the Minimum System with Peak Load Carrying Capability (PLCC) Adjustment (commonly referred to as the ceiling). HHHI is proposing to increase the fixed charge from $29.38 to $48.43.

In three rate classes, the fixed charge is presently below the ceiling, and HHHI is proposing to increase it above the ceiling. These are General Service 50 to 999 kW, General Service 1,000 to 4,999 kW, and Street Lighting.

Question(s):

a) Please provide the variable charges that would result from
   i. Keeping the general service < 50 kW fixed charge at the present 2020 charge of $29.38
   ii. Increasing the fixed charges for the General Service 50 to 999 kW, General Service 1,000 to 4,999 kW, and Street Lighting rate classes to the respective ceiling charges.

Response:

a) Variable charges
   i. Please see Table Staff IRR – 21 below.

   ii. Please see Table Staff IRR – 21 below.

Table Staff IRR – 21

Rate Class	Connection	Customer	kW	kWh
Residential	-	37.31	-	-
General Service less than 50 kW	-	29.38	-	0.0266
General Service 50 to 999 kW	-	127.63	7.2250	-
General Service 1,000 to 4,999 kW	-	376.58	8.4170	-
Sentinel Lights	-	10.25	38.8900	-
Street Lighting	2.58	-	3.8626	-
Unmetered Scattered Load	-	23.00	-	0.0156

Standby Charge

8 - Staff IRR - 76

8-Staff-76
Ref: Exhibit 8, pages 16-17.

Preamble:

HHHI states that it "was approached by a customer (Customer 1 as referred to in Exhibit 3) who is installing a PSUP - Combined Heat and Power ("CHP") CDM program in 2020. The CHP will reduce the customer's demand. The customer has requested that HHHI retains stand-by capacity."

HHHI has referenced the OEB Staff Report to the Board - Rate Design for Commercial and Industrial Electricity Customers - Rates to Support an Evolving Energy Sector. It "is proposing the below calculated Stand-by / Capacity Reserve Charge for Customer 1 based on a CHP faceplate capacity of 1,200 kW and the Capacity Factor of 65%."
With respect to billing, HHHI states that:

> Delivery Component Standby Charge - the charge is based on the applicable General Service 50 to 999 kW or General Service 1,000 to 4,999 kW Distribution Volumetric Charge applied to the contracted amount (e.g. nameplate rating of generation facility multiplied by Capacity Factor).

Question(s):

a) Would the standby charge apply to any customers that have already installed energy resources such as load displacement generation prior to 2020? If so, please provide details on the amount of installation date, amount of load displaced, how the facility would be operated (to displace load, peak shave, etc.), and how HHHI would apply standby charges to these customers.

b) Was the prospective standby customer, and any other anticipated standby customers consulted regarding the standby proposal, and what were the responses?

c) How was the capacity factor of 65% selected?

d) Will there be an opportunity for the capacity factor to be adjusted in future years for actual operation?

e) Please provide sample tariff and/or conditions of service wording that would reflect the proposal to use a capacity factor of 65% for this customer, and how any future standby customers would be charged.

f) Please provide any capacity thresholds that would apply to customers requiring new standby service.

g) Would standby customers be subject to gross load billing for RTSRs? If so, please provide details with respect to the scenarios under which gross load billing would apply, and how the volumes would be determined.

h) Please provide examples for how customers would be charged under a variety of scenarios
   i. The load displacement facility operates the entire month without interruption or outage.
   ii. The load displacement facility experiences a full outage, and HHHI is required to provide backup service.
   iii. The load displacement facility experiences a partial outage, and HHHI is required to provide backup service.
   iv. A customer owns a generator and can instantly shed load to not require a backup service.
   v. A customer owns a generator and operates it intermittently such that it frequently exposes its full load to HHHI.

Response:

a) Currently, HHHI is not aware of any installed energy resources such as load displacement in HHHI's service area.

b) The standby customer was notified at the time they conducted the cost/benefit analysis of the potential for a standby charge. Later, the customer was contacted by HHHI's President & CEO about the prospective standby charges. The customer had no other response than appreciation for the information. The customer also received a copy of the Notice of Hearing.

c) The capacity factor of 65% was taken from the *OEB Staff Report to the Board - Rate Design for Commercial and Industrial Electricity Customers - Rates to Support an Evolving Energy Sector* (EB-2015-0043) ("Evolving Energy Sector Report") Table 6 page 43.

d) HHHI is open to discussions with customers who request a review of the capacity factor in future years after actual operations.

e) Please see Exhibit 8, pages 16 and 17 for Tariff Sheet wording.

f) If an existing customer requests capacity reserves, there would be no new capacity thresholds required. If a new customer requests capacity reserves, HHHI would follow the existing procedures for new services, including communications with upstream providers.

g) HHHI has been in contact with the upstream transmitter and was informed that Gross Load Billing for RTSRs would likely apply. At this time, HHHI is continuing discussions and awaiting reports from the upstream transmitter related to the CHP installation and another battery storage customer who is interested in offsetting peak demand for coincident peaks related to the Class A ICI program.

h) Examples of Charges

i. Please see Table Staff IRR – 22.

ii. Please see Table Staff IRR – 22.

iii. Please see Table Staff IRR – 22.

iv. Please see Table Staff IRR – 22.

v. Please see Table Staff IRR – 22.

Table Staff IRR – 22 – Standby / CRC Examples

IR Reference	Example	Total Peak Demand for the month	Faceplate Capacity (kW)	CHP Capacity Factor (%)	Monthly Reservce Capacity (kW)	Reserve Capacity used at Peak	Remaining Demand not Offset	Propose Volumetric Charge	Standby Charge for the Month	Volumetric Charge for the Month
Example (i)	The load displacement facility operates the entire month without interruption or outage	1100	1000	65%	650	650	450	$ 7.59	$ 4,935.32	$ 3,416.76
Example (ii)	The load displacement facility experiences a full outage, and HHHI is required to provide backup service	1100	1000	65%	650	0	1100	$ 7.59	$ -	$ 8,352.08
Example (iii)	The load displacement facility experiences a partial outage, and HHHI is required to provide backup service	1100	1000	65%	650	300	800	$ 7.59	$ 2,277.84	$ 6,074.24
Example (iv)	A customer owns a generator and can instantly shed load to not require a backup service	1100	1000	65%	650	650	450	$ 7.59	$ 4,935.32	$ 3,416.76
Example (v)	A customer owns a generator and operates it intermittently such that it frequently exposes its full load to HHHI	1100	1000	65%	650	0	1100	$ 7.59	$ -	$ 8,352.08

Retail Transmission Service Rates

8 - Staff IRR - 77

8-Staff-77

Ref: RTSR Model, Tab 3. RRR Data: Tab 5: Historic Wholesale
EB-2019-0039 Rate Generator Model Tab: 4. Billing Det. For Def-Var, Tab: 12: Historic Wholesale

Preamble:

The historic Wholesale and Retail volumes are provided as follows.

	EB-2019-0039	RTSR Model	Change
Wholesale			
Network	1,080,688 kW	1,013,819 kW	-6.2%
Line Connection	1,115,337 kW	1,044,880 kW	-6.3%
Transformation Connection	1,115,337 kW	1,033,799 kW	-7.3%
Retail			
Residential	208,411,376 kWh	202,110,918 kWh	-3.0%
General Service < 50 kW	51,979,121 kWh	50,654,668 kWh	-2.5%
General Service 50 – 999 kW	403,515 kW	418,610 kW	3.7%
General Service 1,000 – 4,999 kW	248,453 kW	219,091 kW	-11.8%
Unmetered Scattered Load	953,473 kWh	962,029 kWh	0.9%
Sentinel Light	695 kW	680 kW	-2.2%
Street Light	3,043 kW	3,105 kW	2.0%

Wholesale volumes have decreased approximately 6-7%, while Retail volumes have typically varied between a decrease of 2.5% and an increase of 2.0%. If the General Service 50-999 kW and General Service 1,000 – 4,999 kW rate classes were viewed in aggregate, it would fall in this range as well.

	EB-2019-0039	RTSR Model	Change
General Service 50 – 999 kW	403,515 kW	418,610 kW	3.7%
General Service 1,000 – 4,999 kW	248,453 kW	219,091 kW	-11.8%
Total	**651,968 kW**	**637,701 kW**	**-2.2%**

Question(s):

a) Please confirm that the tables above reflect the quantities underpinning the approved RTSRs in EB-2019-0039, and the proposed RTSRs in this proceeding, or correct as appropriate.

b) Please explain why wholesale quantities have decreased more than retail quantities.

Response:

a) HHHI does not agree with the tables above. The value under the EB-2019-0039 column for the General Service 50-999 kW rate class is incorrect. The 403,515 kW showing does not include the Wholesale Market Participant demand of 7,360 kW. The correct value should be 410,875. For ease, HHHI has corrected the Table and shows it below:

Table Staff IRR – 23 – Historic Wholesale and Retail Volumes

	Units	EB-2019-0039	RTSR Model	Calculated Change
Wholesale				
Network	kW	1,080,688	1,013,819	(6.19)%
Line Connection	kW	1,115,337	1,044,880	(6.32)%
Transformation Connection	kW	1,115,337	1,033,799	(7.31)%
Retail				
Residential	kWh	208,411,376	202,110,918	(3.02)%
General Service < 50 kW	kWh	51,979,121	50,654,668	(2.55)%
General Service 50 – 999 kW	kW	410,875	418,610	1.88%
General Service 1,000 – 4,999 kW	kW	248,453	219,091	(11.82)%
General Service >50kW		659,328	637,701	(3.28)%
Unmetered Scattered Load	kWh	953,473	962,029	0.90%
Sentinel Light	kW	695	680	(2.16)%
Street Light	kW	3,043	3,105	2.04%

b) Retail quantities are relatively consistent with variations due to weather and growth. Wholesale quantities should also be relatively consist, however, as a result of a request by HONI to move load from one feeder to another for maintenance, HHHI was double peak billed for transmission charges in 2018. Thus, the 2018 wholesale quantities were inflated. The EB-2019-0039 rate application used the wholesale and retail quantities from 2018. The RTSR model is populated using the 2019 wholesale and retail quantities. There were no double peak billings from HONI in 2019 so the wholesale quantities dropped back to a "normal" range. Thus, from 2018 to 2019 quantities, the retail remained fairly consistent but the wholesale value was inflated in 2018.

Exhibit 9 – Deferral and Variance Accounts

9 - Staff IRR - 78

9-Staff-78
Ref: Exhibit 9 – 9.5.1 1588 – RSVA – Power – page 52-53

Preamble:

HHHI confirmed that it has fully implemented the OEB's February 21, 2019 accounting guidance for commodity accounts[8]. The accounting guidance was utilized to re calculate and true-up the transactions related to the RPP settlement and the allocation of IESO Charge Type ("CT") 148 – Class B Global Adjustment Settlement Amount going back to January 1, 2017 as was requested by OEB Staff during the interrogatory process in HHHI's 2020 IRM application (EB-2019-0039).

In the decision and order for EB-2019-0039, the OEB stated its expectations that HHHI will apply for disposition of all eligible Group 1 account in its 2021 rate application.

Question(s):

a) Please confirm that no adjustment has been made to balances of Group 1 accounts for any prior periods that were disposed of on a final basis.

b) Please confirm that HHHI is requesting disposition of its 2017, 2018 and 2019 Group 1 DVA balances on a final basis. If this is not the case, please explain.

c) Please confirm that HHI has completed its review of its processes in the context of the commodity accounting guidance and that any required changes to the accounting for Account 1588 and Account 1589 have been implemented as it relates to its 2017, 2018 and 2019 historical balances. If this is not the case, please explain.

d) Please confirm that there are no systemic issues with HHHI's RPP settlement and related accounting processes as it relates to its 2017, 2018 and 2019 historical balances, with respect to compliance with the accounting guidance.

e) If there are any noted issues, please explain whether adjustments to Group 1 DVA balances that have yet to be disposed of on a final basis have been quantified, including balances that have been cleared on an interim basis or not cleared at all in a prior proceeding.

f) If adjustments have not been quantified, please provide a timeline as to when the applicant expects any discrepancies to be resolved.

g) If material adjustments were identified, please provide the following for each adjustment:

[8] OEB -Accounting Guidance Related to Commodity Pass-Through Accounts 1588&1589. February 21, 2019.

i. Quantification and nature of the adjustment
ii. The period in which the adjustment relates to (i.e. in relation to the flow of kWh)
iii. Detailed explanation of the adjustment, including how it was identified, the reason for the adjustment, the impact to each of Accounts 1588 and 1589.
iv. Show how it has been included as a principal adjustment to Account 1589 in the GA Analysis Workform and Account 1588 in Appendix A GA Methodology Description Questions on Accounts 1588 & 1589, Question 1
v. Describe the steps taken to include these adjustments in the DVA Continuity Schedule and balances requested for disposition in this proceeding. Please also provide the cells in the DVA Continuity Schedule where these adjustments were made.
vi. Please provide 1588 net transactions (including principal adjustments) as a percentage of the cost of power purchases as filed in the RRR for each year requested for disposition. If the result is greater than 1%, please explain given this account only captures loss factor differentials.

Response:

a) In Exhibit 9, page 67, HHHI explains "*As is shown in Table 25 - Principal Adjustment Schedule for 2019 (Accounts 1588 & 1589) above, adjustment B0 indicates that the adjustment for 2016 is a credit in the amount of $1,472,098. This amount reduces the balance to account 1588, thus benefitting all customers. HHHI has recovered this amount from the IESO and fully believes that its customers should receive the benefit of the undertaking and not just the effects of the 2017 adjustment that is a debit in the amount of 10 $1,044,741*". As such, HHHI has included the 2016 credit from the IESO in the Group 1 balances.

b) Confirmed.

c) Confirmed.

d) Confirmed.

e) Please see Tables 23, 24 and 25 on pages 63, 64 and 65 in Exhibit 9 for quantified adjustments to USofA 1588 and 1589. No other Group 1 adjustments have been completed.

f) Not applicable.

g) Material Adjustments
   i. Please see description and timing of adjustments on pages 66 to 70 in Exhibit 9.

   ii. Please see description and timing of adjustments on pages 66 to 70 in Exhibit 9.

   iii. Please see description and timing of adjustments on pages 66 to 70 in Exhibit 9.

iv. Please see Appendix 9-9 beginning on page 176 of Exhibit 9 for the GA analysis Workform. In particular, page 184 shows the principal adjustments.

v. Please see Tab Principle Adjustments in the 2021 GA Workform for the 1588 and 1589 principle adjustment details. Table Staff – 23 – Continuity Schedule Cell References for a list of the adjustments by cell reference.

Table Staff – 23 – Continuity Schedule Cell References

Continuity Schedule Year	Cell	DVA	Adjustment Reference	Amount	Total Adjustment
2017	AL31	1588	A1	1,439,853	
			B0	(1,472,098)	
			B1	1,044,741	
			D1	(1,491,431)	
			E1	1,104,174	**625,239**
	AL32	1589	A1	(1,439,853)	
			C1	(406,235)	
			E1	(1,104,174)	**(2,950,262)**
2018	AV31	1588	A2	3,254,468	
			B2	107,603	
			D2	(233,233)	
			E2	413,506	**3,542,344**
	AV32	1589	A2	(3,254,468)	
			C2	406,235	
			E2	(413,506)	**(3,261,739)**
2019	BF31	1588	B3	1,472,098	
			B3	(1,044,741)	
			B3	(107,603)	
			D3	(392,257)	
			E3	(2,332,954)	
			F3	720,098	
			G3	(79,927)	
			H3	554,961	**(1,210,325)**
	BF32	1589	E3	2,332,954	
			H3	(554,961)	**1,777,993**

vi. Please see Table Staff IRR – 24 for 1588 net transactions (including principal adjustments) as a percentage of the cost of power purchases as filed in the RRR for each year requested for disposition. The result is less than 1%.

Table VECC IRR – 24 – 1588 Net Transactions as a percentage of Cost of Power Purchases

	2017		2018		2019		Totals
	Amount ($)	Ref	Amount ($)	Ref	Amount ($)	Ref	
Principle	(1,802,687)		(3,464,226)		2,021,799		(3,245,114)
Adjustments	1,439,853	A1	3,254,468	A2	1,472,098	B3	
	(1,472,098)	B0	107,603	B2	(1,044,741)	B3	
	1,044,741	B1	(233,233)	D2	(107,603)	B3	
	(1,491,431)	D1	413,506	E2	(392,257)	D3	
	1,104,174	E1			(2,332,954)	E3	
					720,098	F3	
					(79,927)	G3	
					554,961	H3	
Total Adjustments	625,239		3,542,344		(1,210,325)		2,957,258
Net Transactions	**(1,177,448)**		**78,118**		**811,474**		**(287,856)**
Purchases	**26,372,895**		**25,384,688**		**28,559,829**		**80,317,413**
					Percentage		**(0.36)%**

9 - Staff IRR - 79

9-Staff-79

Ref: PILs Workform, Tab T8; DVA Workform, Tab 2b;
OEB's Letter "Accounting Direction Regarding Bill C-97" dated July 25, 2019
Exhibit 9, page 44

Preamble:

HHHI has implemented accelerated CCA in the PILs model as a result of the new Accelerated Investment Incentive Program (AIIP). In the OEB's July 25, 2019 letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, it states that:

> The OEB recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB may consider a smoothing mechanism to address this.

The letter also states that:

> The OEB expects Utilities to record the impacts of CCA rule changes in the appropriate account (Account 1592 - PILs and Tax Variances and similar accounts for natural gas utilities and OPG) for the period November 21, 2018 until the effective date of the Utility's next cost-based rate order. For the purposes of increased transparency, the OEB is establishing a separate sub- account of Account 1592 - PILs and Tax Variances – CCA Changes specifically for the purposes of tracking the impact of changes in CCA rules.

In Exhibit 9 regarding the Account 1592 – PILs and Tax Variances, HHI states that

> Currently, HHHI does not have a balance in DVA 1592. In the future, HHHI forecasts a possibility of requiring USofA 1592 and requests that the OEB allow this account and its sub-accounts to remain available to HHHI.

Question(s):

a) Please confirm that all of HHHI's capital additions in the 2021 test year are eligible for the AIIP.

b) Please discuss whether HHHI has considered smoothing of accelerated CCA for all its capital additions and what its conclusion is.

c) Please provide a calculation showing how HHHI would smooth CCA over the IRM period, and what the impact to PILs would be under a smoothed and unsmoothed scenario.

d) Please explain why HHHI has not recorded an amount in Account 1592, for either 2018 or 2019, given that capital additions made after November 21, 2018 would have been eligible for the accelerated deductions.

e) Did HHHI claim any accelerated CCA deductions in 2018 or 2019? Please reconcile this response with the reply in part d).

Response:

a) Confirmed.

b) HHHI did consider the impact of the accelerated CCA on all of its asset additions and concluded that there is not impact to HHHI. Please see parts c and d below.

c) HHHI has business losses carried forward that have been utilized and as a result has elected not to claim any CCA deductions for 2018 and 2019, and plan to do the same for 2020. Given that HHHI has not deducted any CCA, HHHI is of the view that no smoothing is required.

d) In its 2016 Cost of Service rate application (EB-2015-0074), HHHI had no PILs amounts included in rates. Additionally, HHHI did not claim CCA for 2018 and 2019 as explained above. Given that HHHI had no PILs amounts included in 2016 rates and did not claim any CCA for 2018 and 2019, HHHI concluded that no amount should be recorded in Account 1592.

   HHHI is also not requesting any PILs amount in the current application. As explained above, HHHI is claiming deductions for tax purposes which moves HHHI into a loss position. The deductions are pole replacement costs and overhead costs. HHHI capitalized these costs for accounting purposes but expensed them for tax purposes.

   Ministry of Finance of Ontario (MoF) has allowed these deductions in the pass but HHHI understands from industry partners that recently MoF started to disallow these deductions with the auditing of LDC tax returns. As explained above, HHHI is presenting this application assuming these deductions will be allowed for tax purposes in 2021 Test Year, however HHHI is also requesting to continue Account 1592 to record the two (2) deductions in the event MoF were to disallow these deductions for tax purposes.

e) Please see HHHI’s response 9 – Staff IRR – 79 part c.

APPENDIX STAFF IRR – A

Updated Chapter 2 Appendix 2-Z

2021 Forecasted Commodity Prices

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*	non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers	$20.87	$20.87
Global Adjustment ($/MWh)	Impact of the Global Adjustment	$109.47	$109.47
Adjustments ($/MWh)			$3.24
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$133.58**

Commodity Expense
(volumes for the bridge and test year are loss adjusted)

Commodity — 2021 Test Year

Customer Class Name	UoM	Revenue USA #	Expense USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		3,814,730	211,651,049	$ 0.02087	$ 0.13358	$28,351,961
General Service < 50 kW	kWh	4010	4705	-		7,322,402	41,269,398	$ 0.02087	$ 0.13358	$5,665,585
General Service 50 - 999 kW	kWh	4035	4705	8,905,062		119,223,838	10,145,328	$ 0.02087	$ 0.13358	$4,029,263
General Service 1,000 - 4,999 kW	kWh	4010	4705	52,063,342		21,071,550	-	$ 0.02087	$ 0.13358	$1,526,325
Sentinel Lighting	kWh	4025	4705	-		18,729	243,225	$ 0.02087	$ 0.13358	$32,881
Street Lighting	kWh	4025	4705	-		1,018,788	-	$ 0.02087	$ 0.13358	$21,262
Un-metered Scattered Load	kWh	4025	4705	-		-	1,000,511	$ 0.02087	$ 0.13358	$133,648
	kWh	4025	4705					$ 0.02087	$ 0.13358	$0
	kWh	4025	4705					$ 0.02087	$ 0.13358	$0
TOTAL				**60,968,404**		**152,470,038**	**264,309,510**			**$39,760,925**

Class A - non-RPP Global Adjustment — 2021

Customer	Revenue	Expense	Amount	kWh Volume	Hist. Avg GA/kWh ***	Amount
General Service 50 - 999 kW	4035	4707	861,497	9,971,670	0.0864	$861,497
General Service 1,000 - 4,999 kW	4010	4707	4,826,762	66,507,359	0.0726	$4,826,762
	4010	4707				
			5,688,258	76,479,029		**$5,688,258**

Class B - non-RPP Global Adjustment — 2021

Customer Class Name	UoM	Revenue USA #	Expense USA #	Class B Non-RPP Volume	GA Rate/kWh	Amount
Residential	kWh	4006	4707	3,814,730	$ 0.10947	$417,599
General Service < 50 kW	kWh	4010	4707	7,322,402	$ 0.10947	$801,583
General Service 50 - 999 kW	kWh	4035	4707	119,223,838	$ 0.10947	$13,051,434
General Service 1,000 - 4,999 kW	kWh	4010	4707	21,071,550	$ 0.10947	$2,306,703
Sentinel Lighting	kWh	4025	4707	18,729	$ 0.10947	$2,050
Street Lighting	kWh	4025	4707	1,018,788	$ 0.10947	$111,527
Un-metered Scattered Load	kWh	4025	4707			$0
	kWh	4025	4707			$0
Total Volume				**152,470,038**		
TOTAL						**$16,690,895**

		2021 Test Year	RPP		2021 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast				-				
Residential	kWh	211,651,049		28,272,347	3,814,730		79,613	
General Service < 50 kW	kWh	41,269,398		5,512,766	7,322,402		152,819	
General Service 50 - 999 kW	kWh*	10,145,328		1,355,213	128,128,900		2,674,050	
General Service 1,000 - 4,999 kW	kWh*	0		-	73,134,892		1,526,325	
Sentinel Lighting	kWh	243,225		32,490	18,729		391	
Street Lighting	kWh	0		-	1,018,788		21,262	
Un-metered Scattered Load	kWh	1,000,511		133,648	0		-	
SUB-TOTAL		264,309,510		35,306,464	213,438,442		4,454,460	$ 39,760,925
		-		-	-		-	-
Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential				0			417,599	
General Service < 50 kW				0			801,583	
General Service 50 - 999 kW				0			13,912,930	
General Service 1,000 - 4,999 kW				0			7,133,464	
Sentinel Lighting				0			2,050	
Street Lighting				0			111,527	
Un-metered Scattered Load				0			-	
SUB-TOTAL		0		0			22,379,154	$ 22,379,154
							-	-
Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	211,651,049	0.0071	1,502,722	3,814,730	0.0071	27,085	
General Service < 50 kW	kWh	41,269,398	0.0062	255,870	7,322,402	0.0062	45,399	
General Service 50 - 999 kW	kW	30,997	2.6986	83,647	340,087	2.6986	917,760	
General Service 1,000 - 4,999 kW	kW	-	2.6986	-	168,373	2.6986	454,371	
Sentinal Lighting	kW	630	1.9252	1,213	50	1.9252	96	
Street Lighting	kW	-	1.9163	-	3,105	1.9163	5,950	
Un-metered Scattered Load	kWh	1,000,511	0.0062	6,203	-	0.0062	-	
SUB-TOTAL				1,849,656			1,450,660	**3,300,315**
Transmission - Connection								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	211,651,049	0.0059	1,248,741	3,814,730	0.0059	22,507	
General Service < 50 kW	kWh	41,269,398	0.0055	226,982	7,322,402	0.0055	40,273	
General Service 50 - 999 kW	kW	30,997	2.3110	71,633	340,087	2.3110	785,942	
General Service 1,000 - 4,999 kW	kW	-	2.3110	-	168,373	2.3110	389,110	
Sentinal Lighting	kW	630	1.6636	1,048	50	1.6636	83	
Street Lighting	kW	-	1.6298	-	3,105	1.6298	5,060	
Un-metered Scattered Load	kWh	1,000,511	0.0055	5,503	-	0.0055	-	
SUB-TOTAL				1,553,906			1,242,975	**2,796,881**
Wholesale Market Service								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	211,651,049	0.0034	719,614	3,814,730	0.0034	12,970	
General Service < 50 kW	kWh	41,269,398	0.0034	140,316	7,322,402	0.0034	24,896	
General Service 50 - 999 kW	kWh*	10,145,328	0.0034	34,494	128,128,900	0.0034	435,638	
General Service 1,000 - 4,999 kW	kWh*	-	0.0034	-	73,134,892	0.0034	248,659	
Sentinal Lighting	kWh	243,225	0.0034	827	18,729	0.0034	64	
Street Lighting	kWh	-	0.0034	-	1,018,788	0.0034	3,464	
Un-metered Scattered Load	kWh	1,000,511	0.0034	3,402	-	0.0034	-	
SUB-TOTAL				898,652			725,691	**1,624,343**

Class A CBR								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	-	-	-	-	-	-	
General Service < 50 kW	kWh	-	-	-	-	-	-	
General Service 50 - 999 kW	kWh*	-	-	-	9,971,670	0.000256	2,553	
General Service 1,000 - 4,999 kW	kWh*	-	-	-	66,507,359	0.000219	14,548	
Sentinal Lighting	kWh	-	-	-	-	-	-	
Street Lighting	kWh	-	-	-	-	-	-	
Un-metered Scattered Load	kWh	-	-	-	-	-	-	
SUB-TOTAL				-			17,101	17,101
RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	211,651,049	0.0005	105,826	3,814,730	0.0005	1,907	
General Service < 50 kW	kWh	41,269,398	0.0005	20,635	7,322,402	0.0005	3,661	
General Service 50 - 999 kW	kWh*	10,145,328	0.0005	5,073	128,128,900	0.0005	64,064	
General Service 1,000 - 4,999 kW	kWh*	-	0.0005	-	73,134,892	0.0005	36,567	
Sentinal Lighting	kWh	243,225	0.0005	122	18,729	0.0005	9	
Street Lighting	kWh	-	0.0005	-	1,018,788	0.0005	509	
Un-metered Scattered Load	kWh	1,000,511	0.0005	500	-	0.0005	-	
SUB-TOTAL				132,155			106,719	**238,874**
Low Voltage - No TLF adjustme								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh**	203,510,337	0.0046	936,148	3,668,297	0.0046	16,874	
General Service < 50 kW	kWh**	39,681,668	0.0043	170,631	7,041,217	0.0043	30,277	
General Service 50 - 999 kW	kW	30,997	1.8076	56,029	340,087	1.8076	614,742	
General Service 1,000 - 4,999 kW	kW	-	1.8076	-	168,373	1.8076	304,351	
Sentinal Lighting	kW	630	1.3012	820	50	1.3012	65	
Street Lighting	kW	-	1.2748	-	3,105	1.2748	3,958	
Un-metered Scattered Load	kWh**	962,029	0.0043	4,137	-	0.0043	-	
SUB-TOTAL		244,185,661		1,167,764			970,267	**2,138,031**
Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential		20,318	0.57	138,975	345	0.57	197	
General Service < 50 kW		1,683	0.57	11,510	167	0.57	95	
				-				
SUB-TOTAL				150,485			292	**150,777**
SUB- TOTAL				41,059,083			31,347,318	72,406,400
ORECA CREDIT	33.20%			(13,631,615)			0	(13,631,615)
TOTAL				**27,427,467**			**31,347,318**	**58,774,785**

2021 Test Year		
4705 -Power Purchased	$	39,760,925
4707- Global Adjustment	$	22,379,154
4708-Charges-WMS	$	1,880,318
4714-Charges-NW	$	3,300,315
4716-Charges-CN	$	2,796,881
4750-Charges-LV	$	2,138,031
4751-IESO SME	$	150,777
Misc A/R or A/P	$	(13,631,615)
Total	**$**	**58,774,785**

APPENDIX STAFF IRR - B

Halton Hills Hydro Inc. Climate Change Plan

Halton Hills Hydro Climate Change Plan 2020

Background

In May, 2019, the Town of Halton Hills declared a climate change emergency. As part of this declaration, the Town has committed to achieving a net-zero target by 2030.

Along with distribution system enhancements to address climate change, the utility is looking throughout its business to adapt to a changing climate, to reduce the impact of its operations on the environment, and to support Town of Halton Hills initiatives. Specifically, this climate change plan builds on the Halton Hills Hydro 2020 climate change strategy to support the Town's 2020-2025 Corporate Energy Plan and Low Carbon Transition Strategy.

The impact of climate change on utility infrastructure is not only being recognized locally, but is also being considered in other jurisdictions across the globe. Some recent examples include: The State of California recently issued a proposal which would require utilities to incorporate climate change vulnerability assessments into their rate cases; The US Department of Energy has also issued a guide for climate change resilience planning in the electricity sector and the European Union has created a 2030 climate and energy framework.

In recognition of the importance of planning for climate change as an integral part of corporate operations, Halton Hills Hydro has created a climate change budget to support low carbon initiatives and activities. This plan outlines some of the projects this budget may fund.

Supporting Low-Carbon Mobility

Halton Hills Hydro will support the town's goals to facilitate electric vehicle (EV) infrastructure. Through its affiliate companies, the utility has already supported the installation of EV charging stations at the Acton Arena and Mold-Masters SportsPlex as well as two charging stations at the Halton Hills Hydro office.

Halton Hills Hydro will work with the Town of Halton Hills Low-Carbon Mobility subcommittee to evaluate further locations for public charging. The Town's Draft EV Charging Policy identifies a number of potential locations for new public charging facilities. Locations being evaluated by the town are as follows.

Description	Address
Public Use	
Edith St Parking lot	60 Edith St
Georgetown Fairgrounds	1 Park Ave
Willow St Parking lot	14 Willow St N
Halton Hills Fire Department HQ	14007 10th Side Rd
Acton Fire Station	21 Churchill Rd S
Dominion Gardens Park	118 Guelph St
Gellert Community Centre	10241 8 Line
Robert C Austin Operations Centre	11620 Trafalgar Rd
Employee Use	
Town of Halton Hills Town Hall	1 Halton Hills Dr
Fleet Use	

TBD	

Table 1 source: Draft Town of Halton Hills EV Charging Policy v1.2

Halton Hills Hydro will provide funds or in kind services to assist with the installation of these charging facilities as appropriate.

Budget: $66,700

Preparing for EV Charging Impacts

At present time, Halton Hills Hydro's distribution system has adequate capacity to accommodate additional EV charging infrastructure, however, as EV charging stations proliferate, the load on certain aspects of the distribution system could be more impactful. In particular, the demand requirements of Level 2 and Level 3 chargers can be substantial. Level 3 chargers can require peak energy demands of up to 500kW. As these types of chargers begin to proliferate, distribution system assets may need to be upgraded to handle the increased load.

Various projections from the IESO predict anywhere from a 10% to 35% annual increase in EV sales over the next 20 years. Depending on the number and level of chargers installed to meet the requirements of these vehicles, the impact on the power quality and voltage levels on distribution feeders could be significant.

Low Demand Case			Proposed Case			High Demand Case		
Years 1-5 (2020-2024)	Years 6-10 (2025-2029)	Years 11-21 (2030-2040)	Years 1-5 (2020-2024)	Years 6-10 (2025-2029)	Years 11-21 (2030-2040)	Years 1-5 (2020-2024)	Years 6-10 (2025-2029)	Years 11-21 (2030-2040)
10% annual increase in EV sales			20% annual increase in EV sales			35% annual increase in EV sales		
*170 k vehicles by 2024	320 k vehicles by 2029	500 k vehicles by 2040	210 k vehicles by 2024	520 k vehicles by 2029	1,000 k vehicles by 2040	280 k vehicles by 2024	980 k vehicles by 2029	2,300 k vehicles by 2040

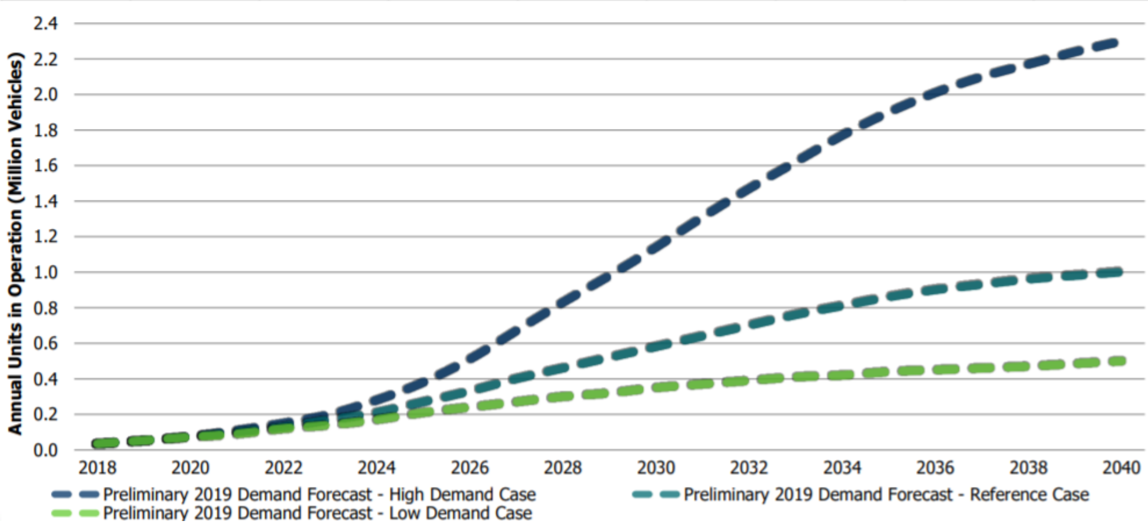

Table 2 Source: IESOPreliminary Long-term Demnd Forecast 2019

Halton Hills Hydro will undertake distribution feeder impact assessments on 4 feeders per year to identify high risk feeders and the potential impacts of EV charging. These assessments will inform decisions on EV charging placement, sizing and technology. These studies may also provide recommendations for smart charging stations that can help alleviate some of the impact of EV charging through managing and balancing EV charging time and draw.

Budget: 4 Feeders per year at $80,000.

Renewable/Low-Carbon Energy

Halton Hills Hydro will assist the Town in its goal to move towards low-carbon or renewable energy sources. This could include combined heat and power (CHP), geothermal installations, battery storage or renewable energy installations such as solar panels. Through its parent company, Halton Hills Hydro has already enabled the installation of roof top solar generation on three Town facilities.

Halton Hills Hydro has contributed to research at McMaster University on an Integrated Community Energy (ICE) Harvesting System demonstration and research project which integrates CHP with thermal energy storage and microgrid technologies. This project, undertaken through the GridSmart City cooperative may provide insights which could benefit the Town's procurement strategies.

Budget: $20,000

Energy Conservation Initiatives

Halton Hills Hydro will assist the Town in improving facility energy efficiency through conservation initiatives. Halton Hills Hydro can draw on its experience in delivering energy conservation programs to assist the town in promoting the Home Retrofit Acceleration Program.

Budget: $60,000

Climate Change Coordinator

To ensure Halton Hills Hydro can effectively and efficiently implement climate change initiatives successfully, a Part-Time Climate Change Coordinator role will be created.

This person will work with the Town of Halton Hills to provide support for its Corporate Energy Plan. As well, they will participate in the advisory committee for the Low Carbon Transition Strategy. The coordinator will analyze sustainability opportunities and innovations to ensure Halton Hills Hydro is positioned to meet the challenges of climate change.

Budget: $53,000

Conclusion

Halton Hills Hydro recognizes the importance of planning for and managing the impacts of climate change. The strategies outlined in this plan will assist the utility and the Town in adapting to the impacts of climate change and in moving towards achieving a net-zero target.

APPENDIX STAFF IRR – C

Streetlight Letter from Town of Halton Hills

TOWN OF
HALTON HILLS
Working Together Working for You!

1 Halton Hills Drive, Halton Hills, L7G 5G2
905-873-2600 | 1-877-712-2205
haltonhills.ca

Reference No.: 20-159

July 29, 2020

Arthur Skidmore, President & Chief Executive Officer
Halton Hills Hydro Inc.
43 Alice Street
Acton ON L7J 2A9

Dear Mr. Skidmore:

RE: Confirmation Letter – Streetlight Conversion to LED

As part of the Town of Halton Hills streetlight fixture conversion to LED fixture project, our contractor, on behalf of the Town of Halton Hills, notified Halton Hills Hydro Inc. of all changes to streetlight fixture wattages on a monthly basis. Original high pressure sodium (hps) streetlight wattages, fixture counts and new LED wattages were reported. As well, counts and wattages were submitted as part of the IESO Save on Energy post project submission.

The energy savings actuals are tracking in line with the projected energy savings.

Should you have any questions, please do not hesitate to contact me.

Regards,

Maureen Ravens

Maureen Van Ravens C.E.T.
Director of Transportation
Transportation & Public Works
Town of Halton Hills
(905) 873-2600 ext. 2314
maureenv@haltonhills.ca

c: Cara Jarv, SouthWestern Energy Inc.

APPENDIX STAFF IRR - D

Town of Halton Hills By-laws

THE CORPORATION OF THE TOWN OF HALTON HILLS

BY-LAW NO. 00-100

A By-law to transfer the assets, liabilities, rights and obligations of the Town of Halton Hills associated with the generation, distribution, transmission and retailing of electricity and associated business activities and all of the assets, liabilities, rights and obligations of The Public Utilities Commission of the Town of Halton Hills to Halton Hills Hydro Inc., Halton Hills Energy Inc., Halton Hills Energy Services Inc. and Halton Hills Fibre Optics Inc.

WHEREAS the Town generates, transmits, distributes and retails electricity through The Public Utilities Commission of the Town of Halton Hills; and

WHEREAS under Section 145(1) of the *Electricity Act, 1998* the Council may make by-laws transferring the assets, liabilities, rights and obligations of the Town of Halton Hills or of a commission or other body through which the Town generates, transmits, distributes or retails electricity to corporations incorporated under the *Business Corporation Act* (Ontario) pursuant to Section 142 of the *Electricity Act, 1998*; and

WHEREAS Council is authorizing the incorporation of Halton Hills Hydro Inc., Halton Hills Energy Inc., Halton Hills Energy Services Inc. and Halton Hills Fibre Optics Inc. under the *Business Corporation Act* (Ontario) pursuant to Section 142(1) of the *Electricity Act., 1998* and Sections 71 and 73 of the *Ontario Energy Board Act, 1998* for the purpose of generating, transmitting, distributing or retailing electricity and associated business activities and the incorporation of any further Subsidiaries necessary or desirable for carrying on any such activities.

The Council of the Town of Halton Hills HEREBY ENACTS as follows:

PART I - INTERPRETATION

1.1 Definitions

For the purposes of this By-law, the following terms shall have the meanings indicated:

"Assets" means, with the exception of the Excluded Assets, all right, title estate, benefit and interest in and to all assets, interests, property, rights, agreements and undertakings, registered or unregistered, secured or unsecured, on the Effective Date of:

(1) the Commission; and

(2) the Town,

held or used by either for the purposes only of generating, distributing, transmitting or retailing electricity or for the purposes of the fibre optics and telecommunications business of either and for the purposes of carrying on associated business activities including, without limitation, the following:

(i) **Cash & Accounts Receivable** – All of the cash on hand and all accounts receivable of the Commission including, without limitation, all customer and trade accounts, notes receivable, book debts and other debts due or accruing to the Commission and all security and security deposits for such accounts and debts;

(ii) **Computer Hardware & Software** – All computer hardware and software, including all rights under licenses and other agreements or instruments relating thereto;

(iii) **Contracts & Rights** – All agreements, contracts, licenses, franchises, commitments, rights, chooses in action, benefits, arrangements and understandings, written or oral, to which the Commission is a party or is otherwise bound or benefited;

(iv) **Development Charge Reserves** – The portion of any reserve funds established pursuant to Sections 33 or 63 of the *Development Charges Act, 1997* that relates to development charges collected and/or accrued in respect of electrical power services, as set out in Schedules D1, D2, D3 and D4;

(v) **Employees** – All full-time and part-time, union and non-union, active and retired, trainee and probationary employees and officers of the Commission on the Effective Date including, without limitation, those identified in Schedules E1, E2, E3 and E4;

(vi) **Employee Agreements** – All contracts, agreements and commitments in respect of employees to which the Commission is a party or by which it is bound as at the Effective Date, including, without limitation, all collective agreements and all contracts of employment and such thereof described in Schedules F1, F2, F3 and F4;

(vii) **Employee Plans** – All employee benefit plans, pension plans, bonus or incentive plans, medical insurance and disability plans, savings plans and other plans relating to employees of the Commission existing as at the Effective Date, including, without limitation, such thereof described in Schedules G1, G2, G3 and G4;

(viii) **Employee Plan Reserves** – The portion of any reserves and funds relative to the employees of the Commission under any employee plans including, without limitation, those described in Schedules H1, H2, H3 and H4;

(ix) **Existing Agreements** – All agreements to which the Commission is a party or by which the Commission is bound, including those identified in Schedules O1, O2, O3 and O4;

(x) **Goodwill** – The goodwill of the Commission including, without limitation:

(a) the exclusive right of the Corporations to represent themselves as carrying on a business in continuation of and in succession to the Commission and the right to use any words indicating that their business is so carried on; and

(b) all records of sales, customer lists, customer data and supplier lists of or used by the Commission;

(xi) **Insurance Policies** – All policies of insurance of the Commission;

(xii) **Intellectual Property** – All trade marks, trade names, brand names, patents and copyrights, registered or unregistered, domestic and foreign, and all patent applications, trade mark registration applications and copyright registration applications, domestic and foreign, owned or made by the Commission including, without limitation, those described in Schedules A1, A2, A3 and A4;

(xiii) **Inventories** – All inventories and supplies of the Commission including, without limitation, all finished goods, work in progress, raw materials, supplies, maintenance items and all other materials and supplies on hand to be used or consumed in the conduct of the business of the Commission;

(xiv) **Know-How** – All patterns, plans, designs, research data, trade secrets and other proprietary know-how, processes, drawings, technology, blueprints, flow-charts, equipment and parts lists and descriptions and related instructions, manuals, data, records and procedures and any and all data owned or used by the Commission, and all licenses, agreements and other commitments relating to any of the foregoing to which the Commission is a party or by which it is bound or benefited;

(xv) **Licenses & Permits** – All licenses, registrations, permits, consents, quotas, approvals, certificates and other authorizations of the Commission including, without limitation, those described in Schedules B1, B2, B3 and B4;

(xvi) **Machinery, Equipment & Tools** – All machinery and equipment, metering and measurement devices, hot water heaters and appliances and all goods and chattels and other personal property and all tools, handling equipment, furniture, furnishings and accessories relating to the business of the Commission including, without limitation, those thereof identified in Schedules P1, P2, P3 and P4;

(xvii) **Plant, Buildings & Fixtures** – All plant, buildings, structures, erections, improvements, appurtenances and fixtures (including fixed machinery and fixed equipment), conduits, pipes, poles, wires, rods, cables, fibres and other apparatus, devices, appliances and equipment, materials, works, transformer stations, transformers, vaults, transmission lines, distribution lines, ducts, pipelines, fittings, apparatus and meters relating to the business of the Commission wheresoever situate on property owned or occupied by the Commission or the Town, on private property or on public property;

(xviii) **Prepaid Expenses** – All pre-paid expenses and all deposits in relation to the business of the Commission;

(xix) **Real Property Interests** – All lands, premises, freehold and leasehold property interests, mortgages, charges, agreements, notices of agreements, debentures and security interests which create an interest in land, liens, easements, rights of way, licenses and rights to use or occupy real property, and all other rights or interests therein and fixtures thereon including, without limitation, those thereof listed in Schedules C1, C2, C3 and C4;

(xx) **Records** – All records, books, documents and data bases of the Commission relating to the Assets, Assumed Liabilities, Employees and the business of the Commission generally, in the possession or under the control of the Commission and all rights of access which the Commission has to records, books, documents and data bases relating to the business of the Commission in the possession of third parties;

(xxi) **Vehicles** – All trucks, cars and vehicles of all kinds used exclusively by the Commission or Town in relation to the business of the Commission including, without limitation, those described in Schedules I1, I2, I3 and I4; and

(xxii) **Warranties** – All warranties and warranty rights, implied, express or otherwise, against manufacturers, suppliers, sellers and others, which relate to any of the Assets and all warranty claims relating to the Assets outstanding as at the Effective Date.

"**Assumed Liabilities**" means all of the debts, liabilities and obligations of the Commission including, without limitation, those described in Schedules J1, J2, J3 and J4, but excluding Excluded Liabilities.

"**Body Corporate**" means a firm, partnership, unincorporated association, joint venture, body corporate, corporation, municipal corporation, bank, trust, pension fund, union, government, government agency, board, tribunal, ministry, commission or other legal entity of any kind whatsoever, excepting a natural person.

"**Commission**" means The Public Utilities Commission of the Town of Halton Hills.

"**Corporations**" means Halton Hills Hydro Inc., Halton Hills Energy Inc., Halton Hills Energy Services Inc. and Halton Hills Fibre Optics Inc. and "**Corporation**" means any one of the Corporations.

"**Effective Date**" means, with respect to any transfer, the date upon which the transfer is effective as set out in Part V of this By-Law.

"**Electricity Act**" means the *Electricity Act, 1998* (Ontario) and regulations, from time to time, thereunder.

"**Excluded Assets**" means the assets identified in Schedules M1, M2, M3 and M4.

"**Excluded Liabilities**" means the liabilities identified in Schedule N.

"**Market Opening**" means the date that Section 26(1) of the Electricity Act is proclaimed in force.

"**OEB Act**" means the *Ontario Energy Board Act, 1998* and regulations, from time to time, thereunder.
"**Person**" means any natural person or Body Corporate.

"**Prescribed Date**" means the date prescribed or determined pursuant to Section 5.6 of this By-law.

"**Prescribed Rate**" means the rate of interest per annum, compounded annually not in advance, prescribed by the Treasurer of the Town, from time to time, which, in any event, shall not be greater than the rate of interest that the particular Corporation could obtain from a Canadian chartered bank or other conventional lender.

"**Standard Supply**" means the sale of electricity pursuant to Section 29 of the Electricity Act.

"**Subsidiary**" shall have the meaning provided for in the *Business Corporations Act* (Ontario).

"**Town**" means the Town of Halton Hills.

1.2 Accounting Terms

All accounting terms not otherwise defined in this By-law shall have the meanings assigned to them in accordance with Canadian generally accepted accounting principles.

1.3 Construction

In this By-law, unless a contrary intention appears, words importing the singular shall include the plural and vice versa and words importing gender shall include all genders.

1.4 Invalid and Ultra Vires Provisions

If any provision in this By-Law is invalid or ultra vires the Town, such provision shall not affect the operation of the remaining portions of this By-Law.

1.5 Schedules

The following Schedules are attached to and form part of this By-law:

Schedules A1, A2, A3 and A4 – Intellectual Property

Schedules B1, B2, B3 and B4 – Licenses and Permits

Schedules C1, C2, C3 and C4 – Real Property Interests

Schedules D1, D2, D3 and D4 – Development Charge Reserves

Schedules E1, E2, E3 and E4 - Employees

Schedules F1, F2, F3 and F4 – Employee Agreements

Schedules G1, G2, G3 and G4 – Employee Plans, Policies and Procedures

Schedules H1, H2, H3 and H4 – Employee Plans Reserves

Schedules I1, I2, I3 and I4 - Vehicles

Schedules J1, J2, J3 and J4 – Assumed Liabilities

Schedules K1, K2, K3 and K4 – Allocation of Consideration

Schedules L1, L2, L3 and L4 – Required Agreements

Schedules M1, M2, M3 and M4 – Excluded Assets

Schedule N – Excluded Liabilities

Schedules O1, O2, O3 and O4 – Existing Agreements

Schedules P1, P2, P3 and P4 – Machinery, Equipment and Tools

Schedule Q – Dispute Resolution

1.6 Binding Effect

This By-law is binding on the Town, the Commission, the Corporations and all other Persons.

1.7 Supremacy of By-Law

In accordance with the Electricity Act, this By-law applies despite any general or special act or rule of law, including any act or rule of law which required notice or registration of transfer; provided, however, the Corporations may register such documents, instruments and agreements, including certified copies of this By-law, as may be necessary or desirable in order to evidence or confirm such transfers.

1.8 Subsidiaries

Where the context requires, Corporations shall include any Subsidiaries.

1.9 Headings

The headings herein are for convenience of reference only and shall not be considered in, or affect, the interpretation of this By-Law.

PART II - CORPORATIONS

2.1 Incorporation of Hydro, Energy and Energy Services

The incorporation of Halton Hills Hydro Inc., Halton Hills Energy Inc. and Halton Hills Energy Services Inc. under the *Business Corporations Act* (Ontario) for the purposes of continuing the generation, transmission, distribution and retailing of electricity and associated business activities of the Commission and the Town is authorized pursuant to Section 142(1) of the Electricity Act and Sections 71 and 73 of the OEB Act.

2.2 Shareholdings in Hydro, Energy and Energy Services

All of the initial shares and other voting securities issued by each of Halton Hills Hydro Inc., Halton Hills Energy Inc. and Halton Hills Energy Services Inc. shall be owned and issued in the name of the Town of Halton Hills.

2.3 Incorporation of FibreCo as a Subsidiary of Hydro

The incorporation of Halton Hills Fibre Optics Inc. under the B*usiness Corporations Act* (Ontario) for the purposes of continuing the fibre optics and associated business activities of the Commission and the Town as a subsidiary of Halton Hills Hydro Inc. is authorized pursuant to Sections 71 and 73 of the OEB Act.

2.4 Shareholdings in FibreCo

All of the initial shares and other voting securities issued by Halton Hills Fibre Optics Inc. shall be owned and issued in the name of Halton Hills Hydro Inc.

2.5 Incorporation of Subsidiaries

The incorporation of any Subsidiaries of the Corporations as are necessary or desirable in the judgement of the directors of the Corporation causing the Subsidiary to be incorporated is authorized.

2.6 **Shareholder Administration**

The Town, in its capacity as initial shareholder of Halton Hills Hydro Inc., Halton Hills Energy Inc. and Halton Hills Energy Services Inc., shall execute and deliver a Shareholder Declaration and Direction and Shareholder's Directives making certain provisions for the organization, management and administration of such Corporations, in a form to be approved by the Council of the Town. Halton Hills Hydro Inc., as the sole initial shareholder of Halton Hills Fibre Optics Inc. and of any other Subsidiary of which it is the sole initial shareholder, shall execute and deliver in respect thereof a Shareholder Declaration and Direction and Shareholder's Directives subjecting such Subsidiary to the same provisions, *mutatis mutandis*, of the Shareholder Declaration and Direction and Shareholder's Directives to which Halton Hills Hydro Inc. is subject.

2.7 **Required Agreements**

Forthwith upon enactment of this By-Law, the Town, the Commission and the Corporations shall in good faith negotiate and enter into such of the Required Agreements described in Schedules L1, L2, L3 and L4 to which each is a party. Any Required Agreements to which the Town is a party shall be approved on behalf of the Town by the Chief Administrative Officer of the Town.

Part III - TRANSFERS

3.1 **Transfer to Halton Hills Hydro Inc.**

On and effective upon the Effective Date all of the Assets and Assumed Liabilities relating to:

(i) the distribution, transmission and Standard Supply of electricity of the Commission and Town and associated businesses; and

(ii) the fibre optics and telecommunications business and associated businesses of the Commission and Town,

are transferred by the Commission and Town to, and are assumed by, Halton Hills Hydro Inc. Included amongst the Assets transferred pursuant to this clause are those of the Assets described in Schedules A1, B1, C1, D1, E1, F1, G1, H1, I1, O1 and P1 and Schedules A4, B4, C4, E4, F4, G4, H4, I4, O4 and P4. Included amongst the Assumed Liabilities transferred pursuant to this clause are those thereof described in Schedule J1 and J4.

3.2 **Transfer to Halton Hills Energy Inc.**

On and effective upon the Effective Date all of the Assets and Assumed Liabilities relating to the generation and retail (excepting Standard Supply) of electricity are transferred by the Commission and Town to, and are assumed by, Halton Hills Energy Inc. Included amongst the Assets transferred pursuant to this clause are those of the Assets described in Schedules A2, B2, C2, D2, F2, G2, H2, I2, O2 and P2. Included amongst the Assumed Liabilities transferred pursuant to this clause are those thereof described in Schedule J2.

3.3 **Transfer to Halton Hills Energy Services Inc.**

On and effective upon the Effective Date all of the Assets and Assumed Liabilities relating to the energy services business of the Commission and Town (being, and including, all the business of the Commission and Town associated with the generation, distribution, transmission and retailing of electricity and associated business activities excepting such thereof transferred by the Commission and Town pursuant to Sections 3.1 and 3.2 of this By-Law) are transferred by the Commission and Town to, and are assumed by, Halton Hills Energy Services Inc. Included amongst the Assets transferred pursuant to this clause are those of the Assets described in Schedules A3, B3. C3, D3, F3, G3, H3, I3, O3 and P3. Included amongst the Assumed Liabilities transferred pursuant to this clause are those thereof described in Schedule J3.

3.4 Transfer by Hydro to FibreCo

On and effective upon the Effective Date all of the Assets and Assumed Liabilities relating to the fibre optics and telecommunications business and associated businesses formerly conducted by the Commission and Town and transferred by them to Halton Hills Hydro Inc. pursuant to Section 3.1 of this By-Law are transferred by Halton Hills Hydro Inc. to, and are assumed by, Halton Hills Fibre Optics Inc. Included amongst the Assets transferred pursuant to this clause are those of the Assets described in Schedules A4, B4, C4, D4, F4, G5, H4, I4, O4 and P4. Included amongst the Assumed Liabilities transferred pursuant to this clause are those thereof described in Schedule J4.

3.5 Sequence of Transfer from Hydro to FibreCo

The transfer by Halton Hills Hydro Inc. to Halton Hills Fibre Optics Inc. of the fibre optics and telecommunications and associated businesses formerly conducted by the Commission and Town pursuant to Section 3.4 of this By-Law shall occur, and by virtue of Section 150(4) of the Electricity Act shall for all purposes be deemed to occur, on the Effective Date in sequence immediately after the transfer of those same businesses to Halton Hills Hydro Inc. from the Commission and Town pursuant to Section 3.1 of this By-Law.

3.6 Transfers to Subsidiaries

Any of the Assets and Assumed Liabilities which are transferred to a Corporation pursuant to this By-law may be transferred by that Corporation to any Subsidiary of that Corporation on such terms and for such consideration as the directors of that Corporation may approve.

3.7 Transfer Documents

The Town, the Commission and each of the Corporations shall enter into any and all agreements and other documents required to give effect to this By-Law and to evidence transfers provided for in this By-Law.

3.8 Excluded Assets and Liabilities

The Excluded Assets and Excluded Liabilities are not transferred to the Corporations by virtue of this By-Law.

3.9 Third Party Consents and Trust

If, notwithstanding this By-law and the Electricity Act, any of the Assets shall not be assignable, or shall only be assignable with the consent or approval of a third party, the Town and Commission shall:

(i) use all efforts in co-operation with the assignee Corporation to secure the consent required in connection with those assignments and all costs of obtaining any consent will be paid by the assignee Corporation; and

(ii) pending the effective transfer thereof, hold all rights and entitlements that the Town or the Commission has thereto in trust for the exclusive benefit of the assignee Corporation, provided that the assignee Corporation shall pay, perform and discharge all obligations arising or accruing with respect thereto during the trust period.

3.10 Registrations

The Town and the Commission shall execute and deliver to the Corporations, where necessary or desirable, in form suitable for registration, recording or filing with such public authorities as may be reasonably required by the Corporations, any bills of sale, assignments and transfers to the Corporations of the right, title, estate and interest of the Town and Commission in and to the Assets.

PART IV – TRANSFER EXEMPTIONS

4.1 Taxation

The transfer of Assets under this By-law is exempt from land transfer tax and retail sales tax as provided in Section 159 of the Electricity Act.

4.2 Legislation

The transfer of Assets under this By-law is exempt from the provisions of all legislation referred to in, or prescribed by regulations made pursuant to, Section 159 of the Electricity Act.

4.3 Goods and Services Tax

The transfer to each Corporation under this By-Law will constitute the transfer of all or substantially all of the assets necessary for that Corporation to carry as a business that portion of the business being transferred to it. The Town and the relevant Corporation, each being registered for Goods and Services Tax purposes, shall sign the necessary election in order for the transfers pursuant to this By-Law not be subject to Goods and Services Tax.

PART V – EFFECTIVE DATES

5.1 Effective Date of Transfer to Halton Hills Hydro Inc.

The Effective Date of the transfer made by the Town and Commission to Halton Hills Hydro Inc. pursuant to Section 3.1 of this By-Law is, and by virtue of section 150(3) of the Electricity Act shall be deemed for all purposes to be, the Prescribed Date.

5.2 Effective Date of Transfer to Halton Hills Energy Inc.

The Effective Date of the transfer made by the Town and Commission to Halton Hills Energy Inc. pursuant to Section 3.2 of this By-Law is, and by virtue of section 150(3) of the Electricity Act shall be deemed for all purposes to be, the Prescribed Date.

5.3 Effective Date of Transfer to Halton Hills Energy Services Inc.

The Effective Date of the transfer made by the Town and Commission to Halton Hills Energy Services Inc. pursuant to Section 3.3 of this By-Law is, and by virtue of section 150(3) of the Electricity Act shall be deemed for all purposes to be, the Prescribed Date.

5.4 Effective Date of Transfer to Halton Hills Fibre Optics Inc.

The Effective Date of the transfer made by Halton Hills Hydro Inc. to Halton Hills Fibre Optics Inc. pursuant to Section 3.4 of this By-Law is, and by virtue of section 150(3) of the Electricity Act shall be deemed for all purposes to be, the Prescribed Date.

5.5 Effective Date of Transfers Pursuant to Part VII

The Effective Date of the transfers made by the Town to Halton Hills Hydro Inc. pursuant to Sections 7.1 and 7.2 of this By-Law is and by virtue of section 150(3) of the Electricity Act shall be deemed for all purposes to be, the Prescribed Date.

5.6 Prescribed Date

The Prescribed Date shall be, for all purposes of this By-law, the date prescribed, and notified to the Corporations in writing, by the Chief Administrative Officer of the Town in consultation with the Halton Hills Hydro Restructuring Committee and shall be November 1, 2000 if a prior date is not prescribed by the Chief Administrative Officer of the Town.

PART VI - PAYMENTS

6.1 Costs

All costs and expenses incurred or to be incurred by the Town and the Commission and all taxes payable in connection with the transfer of the Assets shall be paid by the Corporations and the Corporations shall reimburse the Town and the Commission on demand for any such costs, expenses and taxes paid by the Town and the Commission

6.2 Consideration For Transfers to Halton Hills Hydro Inc.

The Assets transferred to Halton Hills Hydro Inc. pursuant to Section 3.1 of this By-Law shall be transferred at their respective fair market values on the Effective Date. Initially the fair market value of the Assets transferred to Halton Hills Hydro Inc. shall be the book value thereof on the Effective Date and such value shall be adjusted pursuant to Section 6.13 of this By-law.

6.3 Payment by Halton Hills Hydro Inc.

The consideration payable by Halton Hills Hydro Inc. to the Town for the Assets transferred pursuant to Section 3.1 of this By-Law shall be satisfied as follows:

(a) by the assumption by Halton Hills Hydro Inc. of the Assumed Liabilities referred to in Section 3.1 and Schedules J1 and J4 of this By-Law; and

(b) as to the balance by:

(i) the issuance and allotment to the Town of 1,000 fully paid and non-assessable common shares of Halton Hills Hydro Inc. having an ascribed value equal to fifty per cent of such balance, which amount shall be added to the stated capital account for such shares; and

(ii) the issuance by Halton Hills Hydro Inc. to the Town of a promissory note having a principal amount equal to fifty per cent of such balance, being due and payable on the fifth anniversary of the Effective Date, bearing interest at the Prescribed Rate and being otherwise in form and content satisfactory to the Treasurer of the Town.

6.4 Consideration For Transfers to Halton Hills Energy Inc.

The Assets transferred to Halton Hills Energy Inc. pursuant to Section 3.2 of this By-Law shall be transferred at their respective fair market values on the Effective Date. Initially the fair market value of the Assets transferred to Halton Hills Energy Inc. shall be the book value thereof on the Effective Date and such value shall be adjusted pursuant to Section 6.13 of this By-law.

6.5 Payment by Halton Hills Energy Inc.

The consideration payable by Halton Hills Energy Inc. to the Town for the Assets transferred pursuant to Section 3.2 of this By-Law shall be satisfied as follows:

(a) by the assumption by Halton Hills Energy Inc. of the Assumed Liabilities referred to in Section 3.2 and Schedule J2 of this By-Law; and

(b) as to the balance by:

(i) the issuance and allotment to the Town of 1,000 fully paid and non-assessable common shares of Halton Hills Energy Inc. having an ascribed value equal to fifty per cent of such balance, which amount shall be added to the stated capital account for such shares; and

(ii) the issuance by Halton Hills Energy Inc. to the Town of a promissory note having a principal amount equal to fifty per cent of such balance, being due and payable on the fifth anniversary of the Effective Date, bearing interest at the Prescribed Rate and being otherwise in form and content satisfactory to the Treasurer of the Town.

6.6 Consideration For Transfers to Halton Hills Energy Services Inc.

The Assets transferred to Halton Hills Energy Services Inc. pursuant to Section 3.3 of this By-Law shall be transferred at their respective fair market values on the Effective Date. Initially the fair market value of the Assets transferred to Halton Hills Energy Services Inc. shall be the book value thereof on the Effective Date and such value shall be adjusted pursuant to Section 6.13 of this By-law.

6.7 Payment by Halton Hills Energy Services Inc.

The consideration payable by Halton Hills Energy Services Inc. to the Town for the Assets transferred pursuant to Section 3.3 of this By-Law shall be satisfied as follows:

(a) by the assumption by Halton Hills Energy Services Inc. of the Assumed Liabilities referred to in Section 3.3 and Schedule J3 of this By-Law; and

(b) as to the balance by:

(i) the issuance and allotment to the Town of 1,000 fully paid and non-assessable common shares of Halton Hills Energy Services Inc. having an ascribed value equal to fifty per cent of such balance, which amount shall be added to the stated capital account for such shares; and

(ii) the issuance by Halton Hills Energy Services Inc. to the Town of a promissory note having a principal amount equal to fifty per cent of such balance, being due and payable on the fifth anniversary of the Effective Date, bearing interest at the Prescribed Rate and being otherwise in form and content satisfactory to the Treasurer of the Town.

6.8 Consideration For Transfers to Halton Hills Fibre Optics Inc.

Those of the Assets transferred by Halton Hills Hydro Inc. to Halton Hills Fibre Optics Inc. pursuant to Section 3.4 of this By-Law relating to the fibre optics and telecommunications business of the Commission and Town shall be transferred for the same consideration paid therefor by Halton Hills Hydro Inc. upon the transfer thereof to it by the Commission and Town, including any adjustments pursuant to Section 6.13 of this By-law.

6.9 Payment by Halton Hills Fibre Optics Inc.

The consideration payable by Halton Hills Fibre Optics Inc. to Halton Hills Hydro Inc. for the Assets transferred pursuant to Section 3.4 of this By-Law shall be satisfied as follows:

(a) by the assumption by Halton Hills Fibre Optics Inc. of the Assumed Liabilities assumed by Halton Hills Hydro Inc. in relation to the fibre optics and telecommunications business transferred to Halton Hills Hydro Inc. by the Commission and Town pursuant to Section 6.3(a) and Schedule J-4 of this By-Law. The Town releases Halton Hills Hydro Inc. from all Assumed Liabilities assumed by Halton Hills Fibre Optics Inc.; and

(b) as to the balance by:

(i) the issuance and allotment to Halton Hills Hydro Inc. of 1,000 fully paid and non-assessable common shares of Halton Hills Fibre Optics Inc. having an ascribed value equal to fifty per cent of such balance, which amount shall be added to the stated capital account for such shares; and

(ii) the issuance by Halton Hills Fibre Optics Inc. to Halton Hills Hydro Inc. of a promissory note having a principal amount equal to fifty per cent of such balance, being due and payable on the fifth anniversary of the Effective Date, bearing interest at the Prescribed Rate and being otherwise in form and content satisfactory to Halton Hills Hydro Inc.

6.10 Maturity of Promissory Notes

Upon the maturity date of the promissory notes referred to in Sections 6.3, 6.5, 6.7, 6.9 and 7.2 of this By-Law, the Town, after consultation with the Corporation that issued the promissory note, may receive cash for the promissory note or may exchange the promissory note for one or more debt instruments of the Corporation that issued the promissory note having form and content satisfactory to the Treasurer of the Town.

6.11 Allocation of Consideration

The consideration payable by the Corporations shall be allocated amongst the Assets transferred as set out in Schedules K1, K2, K3 and K4 and the Town, Commission and Corporations shall report the transfer of the Assets in accordance with the provisions of Schedules K1, K2, K3 and K4.

6.12 Amount of Assumed Liabilities

The amount of the Assumed Liabilities transferred under this By-law to the Corporations on the Effective Date shall be determined by the Treasurer of the Town in consultation with the Corporations.

6.13 Adjustment of Fair Market Value

The fair market values of the Assets transferred pursuant to Sections 3.1, 3.2, 3.3 and 3.4 of this By-Law shall be adjusted by the Treasurer of the Town in consultation with the affected Corporation taking into account:

(i) the permitted rate of return on equity and the rates that the Ontario Energy Board will allow Halton Hills Hydro Inc. to charge for the distribution of electricity;

(ii) the initial Ontario Energy Board rate order fór the year of Market Opening and subsequent years; and

(iii) any valuation of the Assets by an independent valuator subsequent to the enactment of this By-law.

The amount of any adjustment and the manner of payment of any additional consideration payable by a Corporation pursuant to this Section or the manner of reducing any consideration already paid by any Corporation pursuant to this By-law shall be determined by the Treasurer of the Town in consultation with the affected Corporations.

6.14 Effective Date of Adjustments

All adjustments to the consideration payable by the Corporations to the Town under this By-law shall have the same effect as if they were made on the relevant Effective Date.

6.15 Security

Halton Hills Hydro Inc. shall grant in favour of the Town, and shall cause Halton Hills Energy Inc. and Halton Hills Energy Services Inc. to grant in favour of the Town, a first, fixed and floating charge over the assets of those Corporations to secure payment of any indebtedness of those Corporations to the Town including, without limitation, pursuant to the promissory notes issued by Halton Hills Hydro Inc. pursuant to Sections 6.3 and 7.2 of this By-Law. Halton Hills Fire Optics Inc. shall grant in favour of Halton Hills Hydro Inc. a first, fixed and floating charge over the assets of Halton Hills Fibre Optics Inc. to secure payment of any indebtedness of Halton Hills Fibre Optics Inc. to Halton Hills Hydro Inc. including, without limitation, the promissory note issued by Halton Hills Fibre Optics Inc. pursuant to Section 6.9 of this By-Law.

6.16 Indemnity

Each Corporation shall be bound by, assume, pay, satisfy, discharge, observe, perform and fulfil, and indemnify and save harmless the Town from and against, the Assumed Liabilities assumed by it. The Town shall be bound by, assume, pay, satisfy, discharge, observe, perform and fulfil, and indemnify and save harmless each affected Corporation from and against, all Excluded Liabilities.

6.17 Release of Transferor

Any liability and obligation transferred by this By-Law may only be enforced against the transferee after the Effective Date of the transfer and may not after the Effective Date be enforced against the transferor. The transfer of a liability or obligation by this By-Law releases the transferor from the liability or obligation.

6.18 Reserves

The Development Charge Reserves transferred to the Corporations shall be used only to pay for capital costs in respect of electrical power services for which the Development Charge Reserves were collected.

PART VII - RESTRUCTURING

7.1 Transfer of Shares of Energy and Energy Services

On and effective on the Effective Date, all of the shares of Halton Hills Energy Inc. and Halton Hills Energy Services Inc. received by the Town pursuant to Sections 6.5, 6.7 and 6.13 of this By-Law are transferred by the Town to Halton Hills Hydro Inc. In consideration for such assignment Halton Hills Hydro Inc. shall issue to the Town such number of fully paid and non-assessable common shares of Halton Hills Hydro Inc as is equal in value to the fair market value of the common shares of Halton Hills Energy Inc. and Halton Hills Energy Services Inc. received by Halton Hills Hydro Inc. from the Town pursuant to this Section. The Treasurer of the Town shall determine such fair market values in consultation with Halton Hills Hydro Inc. and the affected Corporations.

7.2 Assignment and Replacement of Energy and Energy Services Promissory Notes

On and effective on the Effective Date, all of the right, title, estate, benefit and interest of the Town in, to and under all promissory notes issued to the Town by Halton Hills Energy Inc. and Halton Hills Energy Services Inc. pursuant to Sections 6.5, 6.7 and 6.13 of this By-Law are transferred by the Town to Halton Hills Hydro Inc. In consideration for such transfer Halton Hills Hydro Inc. shall issue to the Town a promissory note for an amount equal to the collective amount of the promissory notes transferred by the Town to Halton Hills Hydro Inc. pursuant to this Section, and otherwise having the same terms as the promissory notes transferred.

7.3 Sequence of Exchange of Shares and Promissory Notes

The exchange of shares and promissory notes pursuant to Sections 7.1 and 7.2 of this By-Law shall occur, and by virtue of Section 150(4) of the Electricity Act shall for all purposes be deemed to occur, on the Effective Date immediately following the transfers pursuant to Sections 3.1, 3.2 and 3.3 of this By-Law.

PART VIII - MISCELLANEOUS

8.1 Dispute Resolution

In the event of any disagreement amongst any of the Town, the Commission and the Corporations with respect to the effect of, performance required pursuant to or the interpretation of this By-Law, any of the Town, the Commission or the Corporations may by notice to all others affected submit the disagreement to arbitration to be conducted pursuant to Schedule Q to this By-law.

8.2 Further Assurances

The Town, the Commission and each Corporation shall each take and refrain from taking all action necessary or desirable to give effect to the provisions of this By-Law.

ENACTED AND PASSED this 8th day of August, 2000.

M. Sergeantson

Mayor

Clerk

Town of Halton Hills By-law No. 00-100

SCHEDULES A1, A2, A3 and A4

Intellectual Property

Schedule A1: To Hydro

All intellectual property that pertains to the business, assets and liabilities transferred to Halton Hills Hydro Inc. pursuant to this By-law and all intellectual property which does not pertain exclusively to the business, assets and liabilities transferred to another Corporation, excluding all intellectual property identified in Schedules A2, A3 and A4, but including:

- Halton Hills Hydro logos
- all copyrights (electronic and media form) and applications thereof
- all trademarks and applications therefor
- all patents and applications therefor

Schedule A2: To Energy

There is no intellectual property transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule A3: To Services

All intellectual property that pertains exclusively to the business, assets and liabilities transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule A4: To FibreCo

All intellectual property that pertains exclusively to the business, assets and liabilities transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law.

Town of Halton Hills By-law No. 00-100

SCHEDULES B1, B2, B3 and B4

Licenses and Permits

Schedule B1: To Hydro

All licenses and permits that pertain to the business, assets and liabilities transferred to Halton Hills Hydro Inc. pursuant to this By-law and all licenses and permits which do not pertain exclusively to the business, assets and liabilities transferred to another Corporation, excluding all licenses and permits identified in Schedules B2, B3 and B4, but including:

- Local Distribution License Number ED-1999-0290
- Computer hardware and software licenses
- PCB Registration and Fuel Storage Licenses
- Mobile radio licenses
- SCADA radio license

Schedule B2: To Energy

There are no licenses and permits transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule B3: To Services

All licenses and permits that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule B4: To FibreCo

All licenses and permits that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law, including:

- Communications and radio licenses excepting mobile and SCADA radio licenses

Town of Halton Hills By-law No. 00-100

SCHEDULES C1, C2, C3 and C4

Real Property Interests

Schedule C1: To Hydro

All real property interests that pertain to the business, assets and liabilities transferred to Halton Hills Hydro Inc. pursuant to this By-law and all real property interests which do not pertain exclusively to the business, assets and liabilities transferred to another Corporation, excluding all real property interests identified in Schedules C2, C3 and C4, but including:

- all lands and buildings
- all substation, transmission and transformer locations
- all easements, rights of ways and real property licenses
- all poles, wires and pole attachments
- all distribution systems and equipment
- land and buildings at 43 and 39 Alice Street, Acton, Ontario

Schedule C2: To Energy

There are no real property interests transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule C3: To Services

There are no real property interests transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule C4: To FibreCo

All real property interests that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law.

- all pole attachments for fibre optics cables and equipment
- all easements, rights of way and licenses for fibre optics cables
- all railway and roadway crossing rights for fibre optics cables

Town of Halton Hills By-law No. 00-100

SCHEDULES D1, D2, D3 and D4

Development Charge Reserves

Schedule D1: To Hydro

All Development Charge Reserves related to development charges collected and/or accrued with respect to electrical power services.

Schedule D2: To Energy

There are no Development Charge Reserves transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule D3: To Services

There are no Development Charge Reserves transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule D4: To FibreCo

There are no Development Charge Reserves transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law.

Town of Halton Hills By-law No. 00-100

SCHEDULES E1, E2, E3 and E4

Employees

Schedule E1: To Hydro

All employees referred to in Section 1.1(v) of this By-law and all records and information whatsoever, including personal information, relating to such employees and all liabilities, obligations and rights relating to such employees. No such employee shall be terminated by virtue of this By-law.

Schedule E2: To Energy

There are no employees transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule E3: To Services

There are no employees transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule E4: To FibreCo

There are no employees transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law.

Town of Halton Hills By-law No. 00-100

SCHEDULES F1, F2, F3 and F4

Employee Agreements

Schedule F1: To Hydro

All contracts, agreements and commitments in respect of employees referred to in Section 1.1(v) of this By-law to which the Commission is a party or by which the Commission is bound, including:

- the Collective Agreement with the Power Workers' Union CUPE Local 1000 for April 1, 1999 to March 31, 2001
- Pay Equity Agreement
- "Job Evaluation" Tool – Peat Marwick Consulting
- all End-of-Service Agreements

Schedule F2: To Energy

There are no employee agreements transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule F3: To Services

There are no employee agreements transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule F4: To FibreCo

All employee agreements that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law, including:

- the Services Agreement with Cheryl Sawa

Town of Halton Hills By-law No. 00-100

SCHEDULES G1, G2, G3 and G4

Employee Plans, Policies and Procedures

Schedule G1: To Hydro

All plans referred to in Section 1.1(vii) of this By-law, including:

- Ontario Municipal Employees Retirement System (OMERS) Pension Plan
- Employee Benefit Program for Union Employees (MEARIE)
- Employee Benefit Program for Management Employees (MEARIE)
- Employees Policies, Procedures and Directives Handbook

Schedule G2: To Energy

There are no plans referred to in Section 1.1(vii) of this By-law that are transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule G3: To Services

There are no plans referred to in Section 1.1(vii) of this By-law that are transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule G4: To FibreCo

There are no plans referred to in Section 1.1(vii) of this By-law that are transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law.

Town of Halton Hills By-law No. 00-100

SCHEDULES H1, H2, H3 and H4

Employee Plans Reserves

Schedule H1: To Hydro

Any reserves or funds relative to employees of the Commission and information pertaining thereto under any Employee Plan are transferred to Halton Hills Hydro Inc.

Schedule H2: To Energy

There are no reserves or funds relative to employees of the Commission under any Employee Plans transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule H3: To Services

There are no reserves or funds relative to employees of the Commission under any Employee Plans transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule H4: To FibreCo

There are no reserves or funds relative to employees of the Commission under any Employee Plans transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law.

Town of Halton Hills By-law No. 00-100

SCHEDULES I1, I2, I3 and I4

Vehicles

Schedule I1: To Hydro

All trucks, cars and vehicles (including installed radio communication equipment) referred to in Section 1.1(xx) of this By-law, including those listed on the following page.

Schedule I2: To Energy

There are no trucks, cars or vehicles of any kind of the Commission or Town transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule I3: To Services

There are no trucks, cars or vehicles of any kind of the Commission or Town transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule I4: To FibreCo

There are no trucks, cars or vehicles of any kind of the Commission or Town transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law.

VEHICLE RECORD

	NO.	MAKE	YEAR	TYPE	V.I.N.	POWER	REG. WT.	DEPT.	LIC. NO.
1	101	INTERNATIONAL	1994	ALTEC DIGGER DERRICK	1HTGKA6R5RH552132	D	28000 LBS.	OPERATIONS	YC3104
2	102	INTERNATIONAL	1994	ALTEC SINGLE BUCKET	1HTGBPCR2RH552130	D	15000 LBS.	OPERATIONS	XW2331
3	103	FORD	1990	1/2 TON 4X4 TRUCK	1FTEF14NOLKB28781	G	3000 LBS	MECHANIC	TZ1680
4	105	INTERNATIONAL	1998	WAJAX SINGLE BUCKET	1HTGMAAR7WH532929	D	15000 LBS.	OPERATIONS	3072DK
5	109	INTERNATIONAL	1998	AMADOR DOUBLE BUCKET	1HTGLAUT5WH495342	D	31000 LBS.	OPERATIONS	5899CY
6	108	FORD	1995	1/2 TON 4X4 TRUCK	2FTEF14N3SCA46031	G	3000 LBS.	HODGE	ZL2063
7	112	CHEVROLET	1992	ASTRO MINI-VAN	1GCDM15Z6NB167655	G	3000 LBS.	ENGINEERING	WW9496
8	114	CHEVROLET	1995	ASTRO MINI-VAN	1GCDM19W4SB148050	G	3000 LBS.	SPEILVOGEL	ZM2029
9	115	CHEVROLET	2000	ASTRO MINI-VAN	1GCDL19W8YB167440	G	3000 LBS.	BECKER	4789HS
10	117	FORD	1995	AEROSTAR MINI-VAN	1FTDA14U9SZA41291	G	3000 LBS.	ENGINEERING	ZM2032
11	118	CHEVROLET	1995	COMPACT 1/2 TON 4X4	1GCCT19Z1SK152775	G	3000 LBS.	DURSKI	ZX8867
12	120	CHRYSLER	1998	4X4 JEEP	1J4FJ28S4WL260413	G	3000 LBS.	GUATTO	ACFV891
13	122	CHEVROLET	1988	ALTEC DOUBLE BUCKET	1GBM7D1Y6JV114442	D	25000 LBS.	OPERATIONS	OX9705
14	127	INTERNATIONAL	1992	ALTEC DIGGER DERRICK	1HTGKA6R2NH391877	D	28000 LBS.	OPERATIONS	VN7499
15	128	FORD	1992	1 TON 4X4 TRUCK	2FTJW36H3NCA53776	G	8000 LBS.	HARDING	XC1669
16	129	CHEVROLET	1992	ASTRO MINI-VAN	1GCDM15Z4NB168660	G	3000 LBS.	ENGINEERING	WW9500
17	130	FORD	1995	DUMP BODY	1FDLF47F2SEA78522	D	10000 LBS.	OPERATIONS	2251AK
18	131	FORD	1996	1 TON 4X4 TRUCK	1FTJW36H4TEB23244	G	8000 LBS.	OPERATIONS	9630AV

TRAILER RECORDS

H2

NO.	DESCRIPTION	YEAR	WEIGHT	LIC. NO.	VIN
201	TENNSION PULLER	1998	2000 KG	N/A	N/A
202	TENNSION PULLER	1989	2000 KG	L34838	FILE-158694540
203	HOTSTICK	1991	1240 KG	L34837	FILE-158694435
204	POLE TRAILER	1985	2250 KG	84874M	FILE-092245112
205	MATERIAL TRAILER	1985	1860 KG	K50920	FILE-092245695
206	ARROW BOARD	1994	N/A	N/A	N/A
207	UTILITY TRAILER	1995	1800 KG	N64495	HOMO7N95461028555
208	GENERATOR	1985	6590 KG	X17032	1GRAA6017FS111208

Town of Halton Hills By-law No. 00-100

SCHEDULES J1, J2, J3 and J4

Assumed Liabilities

Schedule J1: To Hydro

All debts, liabilities and obligations that pertain to the business, assets and liabilities transferred to Halton Hills Hydro Inc. pursuant to this By-law and debts, liabilities and obligations which do not pertain exclusively to the business, assets and liabilities transferred to another Corporation, excluding all debts, liabilities and obligations identified in Schedules J2, J3 and J4, but including:

- trade payables
- environmental claims, known and unknown, relating to the real property interests identified in Schedule C1 to this By-law
- a Class Action lawsuit claiming against all Ontario Municipal Utilities restitutionary payments in respect of late penalty fees on overdue utility bills since April 1, 1981
- all insurance claims, known and unknown
- all liabilities associated with agreements referred to in Schedule L1

Schedule J2: To Energy

There are no debts, liabilities or obligations transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule J3: To Services

All debts, liabilities and obligations that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Energy Services Inc. pursuant to this By-law, including:

- trade payables
- liabilities associated with water heaters and leasing
- all liabilities associated with agreements referred to in Schedule L3

Schedule J4: To FibreCo

All debts, liabilities and obligations that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law, including:

- trade payables
- environmental claims, known and unknown, relating to the real property interests identified in Schedule C4 to this By-law
- all liabilities associated with agreements referred to in Schedule L4

Town of Halton Hills By-law No. 00-100

SCHEDULES K1, K2, K3 and K4

Allocation of Consideration

Schedule K1: To Hydro

The consideration, and adjusted consideration, relative to the Assets transferred to Halton Hills Hydro Inc. will be allocated, for all and each purpose, to the various classes of such Assets so as to maximize the benefit to such Corporation of such allocations.

Schedule K2: To Energy

The consideration, and adjusted consideration, relative to the Assets transferred to Halton Hills Energy Inc. will be allocated, for all and each purpose, to the various classes of such Assets so as to maximize the benefit to such Corporation of such allocations.

Schedule K3: To Services

The consideration, and adjusted consideration, relative to the Assets transferred to Halton Hills Energy Services Inc. will be allocated, for all and each purpose, to the various classes of such Assets so as to maximize the benefit to such Corporation of such allocations.

Schedule K4: To FibreCo

The consideration, and adjusted consideration, relative to the Assets transferred to Halton Hills Fibre Optics Inc. will be allocated, for all and each purpose, to the various classes of such Assets so as to maximize the benefit to such Corporation of such allocations.

Note: Maximizing the benefit of the allocations for Halton Hills Hydro Inc. is the paramount consideration and maximizing the benefit of the allocations to the other Corporations, being Subsidiaries of Halton Hills Hydro Inc., is secondary and subordinate.

Town of Halton Hills By-law No. 00-100

<u>SCHEDULES L1, L2, L3 and L4</u>

<u>Required Agreements</u>

<u>Schedule L1: Hydro</u>

The Required Agreements for Halton Hills Hydro Inc. are:

- Shareholder Declaration and Direction
- Shareholder's Directive
- The agreements listed in Schedules L3 and L4 for Services and FibreCo to enter into with Hydro
- Rights of Way Agreement with the Town

<u>Schedule L2: Energy</u>

The Required Agreements for Halton Hills Energy Inc. are:

- Shareholder Declaration and Direction
- Shareholder's Directive

<u>Schedule L3: Services</u>

The Required Agreements for Halton Hills Energy Services Inc. are:

- Shareholder Declaration and Direction
- Shareholder's Directive
- Office Space Agreement with Hydro
- Services Agreement with Hydro
- Confidentiality Agreement with Hydro
- Help Desk Agreement with Hydro
- Employee Services Agreement with Hydro
- Branding Agreement with Hydro
- Equipment Useage Agreement

<u>Schedule L4: FibreCo</u>

The Required Agreements for Halton Hills Fibre Optics Inc. are:

- Shareholder Declaration and Direction
- Shareholder's Directive
- Pole Attachment and Duct Useage Agreement with Hydro
- Facilities Services (Design, Installation and Maintenance) Agreement with Hydro
- Rights of Way Agreement with Hydro
- Office Space and Services (Billing etc.) Agreement with Hydro
- Confidentiality Agreement with Hydro
- Help Desk Agreement with Hydro
- Telecommunications Agreement with Hydro
- Branding Agreement with Hydro
- Employee Services Agreement with Hydro
- Equipment Useage Agreement with Hydro

Town of Halton Hills By-law No. 00-100

SCHEDULES M1, M2, M3 and M4

Excluded Assets

Schedule M1: To Hydro

No Assets that pertain to the business transferred to Halton Hills Hydro Inc. pursuant to this By-law are excluded from such transfer except:

- streetlights
- poles and wires used exclusively for streetlights

Schedule M2: To Energy

No Assets that pertain to the business transferred to Halton Hills Energy Inc. pursuant to this By-law are excluded from such transfer.

Schedule M3: To Services

No Assets that pertain to the business transferred to Halton Hills Energy Inc. pursuant to this By-law are excluded from such transfer.

Schedule M4: To FibreCo

No Assets that pertain to the business transferred to Halton Hills Energy Inc. pursuant to this By-law are excluded from such transfer.

Town of Halton Hills By-law No. 00-100

SCHEDULE N

Excluded Liabilities

All liabilities pertaining to the Excluded Assets.

Town of Halton Hills By-law No. 00-100

SCHEDULES O1, O2, O3 and O4

Existing Agreements

Schedule O1: To Hydro

All existing agreements to which the Commission is a Party or by which the Commission is bound that pertain to the business, assets and liabilities transferred to Halton Hills Hydro Inc. pursuant to this By-law and all such agreements which do not pertain exclusively to the business, assets and liabilities transferred to another Corporation and including specifically:

- Tree Trimming Agreement with Colonial Tree Services
- ENERconnect Agreements
- Streetlight Agreement with the Town
- All agreements for the purchase, sale and delivery of electricity
- Joint Use (Pole Attachment) Agreements with Bell, Cogeco and Rogers
- Tower Lease Agreement with Bell Mobility Cellular Inc.
- Meter Reading Services Agreement with Schlumberger
- Tower Land Lease Agreement with Microcell Connexions Inc.

Schedule O2: To Energy

There are no Existing Agreements with respect to Halton Hills Energy Inc.

Schedule O3: To Services

All existing agreements to which the Commission is a Party or by which the Commission is bound that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Energy Services Inc. pursuant to this By-law and including specifically:

- Water Heater Installation and Maintenance Agreement with Georgetown Electric
- Halton Region Water Meter Reading and Billing Agreement
- all agreements for the supply and leasing of water heaters

Schedule O4: To FibreCo

All existing agreements to which the Commission is a Party or by which the Commission is bound that pertain exclusively to the business, assets and liabilities transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law, and including specifically:

- ICS Services Agreement
- SAWA Services Agreement
- Halton Catholic District School Board Services Agreement
- HCDSB Contract Management Agreement
- Northwest GTA Hospital Corporation Services Agreement
- Westlink Interconnect Agreements

Town of Halton Hills By-law No. 00-100

SCHEDULES P1, P2, P3 and P4

Machinery, Equipment, Tools

Schedule P1: To Hydro

All machinery, equipment and tools referred to in Section 1.1(xvi) of this By-law.

Schedule P2: To Energy

There are no machinery, equipment or tools of any kind of the Commission or Town transferred to Halton Hills Energy Inc. pursuant to this By-law.

Schedule P3: To Services

There are no machinery, equipment or tools of any kind of the Commission or Town transferred to Halton Hills Energy Services Inc. pursuant to this By-law.

Schedule P4: To FibreCo

There are no machinery, equipment or tools of any kind of the Commission or Town transferred to Halton Hills Fibre Optics Inc. pursuant to this By-law except:

- computers

Town of Halton Hills By-law No. 00-100

SCHEDULE Q

Dispute Resolution

Any arbitration pursuant to Section 8.1 of this By-law shall be conducted in accordance with the following:

(i) Upon written demand of the notice giver, the representatives of those involved shall meet and attempt to appoint a single arbitrator. In the event that such representatives are unable to agree on a single arbitrator then a single arbitrator shall be appointed by any Justice of the Ontario Superior Court of Justice;

(ii) The arbitrator shall be qualified by education, experience and training to pass upon the particular dispute;

(iii) The arbitrator shall immediately hear and determine all questions in dispute within forty-five (45) days after appointment, subject to any reasonable delay due to unforeseen circumstances. In the event that the arbitrator fails to make a decision within such period, then any involved party may have a new arbitrator chosen as provided herein, as if none had previously be selected;

(iv) The decision of the arbitrator shall be in writing and shall be final and binding upon all parties; and

(v) The arbitration shall be governed in all respects by *The Arbitrations Act* (Ontario) and regulations thereunder.

THE CORPORATION OF THE TOWN OF HALTON HILLS

BY-LAW NO. 01-130

Being a By-law to amend By-law 00-100, regarding the transfer of assets, liabilities, rights, and obligations of the Town of Halton Hills associated with the generation, distribution, transmission, and retailing of electricity and associated business activities, and all the assets, liabilities, rights and obligations of the Public Utilities Commission of the Town of Halton Hills to Halton Hills Hydro Inc., Halton Hills Energy Inc., and Halton Hills Energy Services Inc., and Halton Hills Fibre Optics Inc.

WHEREAS By-law 00-100 was passed by Council for the Corporation of the Town of Halton Hills on the 8th day of August, 2000;

AND WHEREAS Council for the Corporation of the Town of Halton Hills deems it expedient to amend By-law 00-100;

NOW THEREFORE, BE IT RESOLVED THAT THE COUNCIL OF THE CORPORATION OF THE TOWN OF HALTON HILLS ENACTS AS FOLLOWS:

1. THAT the definition of **"Prescribed Rate"** as contained on Page 4 of By-law 00-100 be deleted and replaced with the following:

   "Prescribed Rate" means the rate of interest per annum, compounded annually not in advance, prescribed by the Treasurer of the Town, from time to time.

By-law read and passed by Council for the Town of Halton Hills this 22nd day of October 2001.

Kathy Gastle
Mayor

[signature]
Clerk