PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

July 4, 2022 **VIA E-MAIL**

Ms. Nancy Marconi
Registrar (registrar@oeb.ca)
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

Re: EB-2022-0049 – Milton Hydro Distribution Inc. (Milton Hydro)
January 1, 2023 Cost of Service Rates
Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

Please find attached the interrogatories of VECC in the above-noted proceeding. We have also directed a copy of the same to the Applicant.

Yours truly,

Mark C Garner Digitally signed by Mark C Garner
Date: 2022.07.04 17:19:54 -04'00'

Mark Garner
Consultants for VECC/PIAC

Email copy:

Dan Gapic, Director, Regulatory Affairs, Milton Hydro
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REQUESTOR NAME	**VECC**
TO:	**Milton Hydro Distribution Inc. (MHDI)**
DATE:	**July 4, 2022**
CASE NO:	**EB-2022-0049**
APPLICATION NAME	**2023 Cost of Service Rate Application**

1.0 ADMINISTRATION (EXHIBIT 1)

1.0-VECC-1
Reference: Exhibit 1, page 17

MHDI states its franchise has a : "*Young demographic (largest age group is 35-39) – median age is 3510 (a demographic that is more in touch with climate related initiatives and electric vehicles (EV)), i.e.: willing to invest in EVs."* Yet we note that the Fuels Institute's *EV Consumer Behavior June 2021 Report states: "The average EV owner continues to be male, aged 40-55 years old, with an annual household income of more than $100,000 ($129,000 CDN.)(2019*). https://www.fuelsinstitute.org/

a) What actual evidence does MHDI have to suggest that its franchise areas is any more likely than other parts of Ontario to require EV charging infrastructure in the future?

1.0-VECC-2
Reference: Exhibit 1, page 36

"*Based on customer feedback and preferences, Milton Hydro made changes and re-prioritized some of its investments during the DSP period, with a goal to improving service without increasing its total capital budgets."*

a) What changes did MHDI make to its investments due to customer feedback?

1.0-VECC-3
Reference: Exhibit 1, page 56 / Exhibit 4, page 9

With respect to the inflation assumptions applied by MHDI, the Utility states: "*Milton Hydro notes the issue and will provide further assessment during the proceeding as the situation evolves."*

a) Please explain this statement and specifically address whether MHDI is proposing to amend its application and if so when.

1.0-VECC-4
Reference: Exhibit 1, page 70 / Exhibit 4, page 54

"*70% of Milton Hydro's customers have chosen paperless e-billing.*"

a) Please describe the account opening processes provided to new customers. Specifically, is paper or on-line billing the default option presented.

b) What promotions or incentives does MHDI currently offer to encourage e-billing. What new programs are being offered in the test year and during the rate plan period?

c) Please provide a breakdown of the forms of customer payments for 2021 (i.e., online, cheque, cash).

1.0-VECC-5
Reference: Exhibit 1, page 86

a) Please provide the updated final results 2021 Milton Hydro Scorecard.

1.0-VECC-6
Reference: Exhibit 1, page 100-101

"*Pole Maintenance O&M Unit Cost Index - Milton Hydro's average unit cost index is $29.22, while the Industry average unit cost index is $14.05. Currently Milton Hydro has no visibility or insights as to why its unit cost index is higher from the average distributors unit cost index. Milton Hydro will consult with other distributors who have lower than average unit cost indices to understand the difference between its pole maintenance program and the programs of those distributors with lower unit cost indices, to establish an action plan to reduce its costs*."

"*Milton Hydro's average unit cost index is $30.81, while the Industry average unit cost index is $12.21*."

a) Please explain precisely what plan MHDI has to investigate this and other significant variations from the industry mean in its activity based benchmarks.

1.0-VECC-7
Reference: Exhibit 1, pages 113-

a) MHDI has introduced the management process of Lean and Six Sigma. Six Sigma's goals are to reduce defects and variation so that processes are more consistent and predictable. What metrics will be used to show the success (or lack thereof) of introducing this new management process. Specifically address how the introduction of this program will impact reliability metrics (e.g.,SADI/SAIFI and specific code outages like those due to equipment failure).

b) Please provide the total costs of introducing the "Lean Six Sigma" and Lean Six Sigma belt" programs. Please delineate the costs, by FTE, training, and other significant costs (identify). Please provide the one-time and annual costs separately and delineate between capital from OM&A costs.

c) MHDI notes a number of "soft" savings may occur with the introduction of the Six Sigma processes. Examples given of this are "increased customer satisfaction and increased employee moral". What baseline measurement of employee moral and customer satisfaction is MHDI using to measure whether the program has any discernible affect on these or other "soft savings"?

d) "Improved quality" and "Improved productivity" are other examples offered of the benefits of the Sigma program. Improvement in the quality of what type and productivity of what nature are being contemplated by MHDI management?

e) MHDI states that "*For a rapidly growing utility such as Milton Hydro hard savings are not expected*" from the program. If that is the case then how will success (or failure) of the program be measured in each year of the rate plan? That is how will value for money be demonstrated?

1.0-VECC-8
Reference: Exhibit 1, page 86
"*The entire Senior Management Team (SMT) at Milton Hydro has turned over during the 18-26 month period from Aug 1, 2020, to January 2022*"

a) Was the Milton Hydro 2.0 Strategy and Six Sigma program developed by the new management team? What was the longest tenure of a senior manager at Milton Hydro who assisted in the development of these initiatives?
b) Is MHDI aware of any other electricity utility that has implemented a Lean Six Sigma program? If yes please provide the assessments MHDI of those programs.

2.0 RATE BASE (EXHIBIT 2)

2.0-VECC -9

Reference: Exhibit 2, pages 6, 29

a) Please explain how major spare parts and standby equipment (MSP&SE) was accounted for prior to the change to include them in rate base sought in this application.

b) Please explain what precipitated the change in policy.

c) Please provide the amounts of MSP&SE for each year 2016 through 2020.

d) Please provide an inventory list of the major assets included in the $610k being sought to be included in rate base.

2.0-VECC -10

Reference: Exhibit 2, page 23

a) Given the proposal to include the previously disallowed building space into 2023 rate base, please explain why the account 1908 “Building disallowed in 2016 ($1,429,202) is removed from the 2022 continuity schedule rather than the 2023 schedule.

2.0-VECC -11

Reference: Exhibit 2, Appendix 2-AB

a) Please explain how the capital contribution amount for 2023 of ($2,539,000) was derived.

b) Please confirm (or correct) that the only category of capital projects that attract capital contributions are in System Access.

2.0-VECC -12

Reference: Exhibit 2, DSP Appendix 2, PDF 288

a) Has the bucket truck (“Unit #44 Single Bucket 46’) been ordered and a delivery date confirmed?

2.0-VECC -13

Reference: Exhibit 2, DSP Appendix 2, PDF 311

a) Please provide the implementation Gantt charts for the ERP and Robotic Process Automation Phase 1 and Phase 2.

2.0-VECC -14

Reference: Exhibit 2, /EB-2015-0089, page 53

The following table was provided in the last cost of service application (EB-2015-0089):

Material Capital Expenditures (2016 – 2020)							
Category	Category Total Expenditure	Project Name	2016 $'000	2017 $'000	2018 $'000	2019 $'000	2020 $'000
System Access	$30.0M	Steeles Ave – Industrial to Martin	$284				
		Britannia Rd– RR25 to JSP	$1,005				
		Garden Lane -400m	$133				
		5th Line; LSL to Derry Road	$415				
		5th Line; LSL to Britannia Road	$397				
		Britiannia Rd – RR25 to Tremaine	$403				
		Bronte Street – LSL to Britannia	$390				
		Britannia Rd – JSP to Trafalgar		$1,016			
		Britannia Rd – Trafalgar to 407		$366			
		1st Line – Nassagaweya		$732			
		Thompson Rd – Britannia to LSL		$400			
		LSL – JSP to 5th Line		$191			
		Main St – JSP to 5th Line		$475			
		Campbellville Rd – Milborough to Guelph			$239		
		6th Line – 401 to Derry			$463		
		6th Line – Derry to Britannia			$695		
		Provision for new projects				$1,500	$2,000
		Subdivision development	$3,780	$3,780	$3,780	$3,780	$3,780
System Renewal	$9.2M	Pole Replacement Program	$500	$375	$500	$500	$625
		Porcelain to Poly program	$150				
		Derry Rd – Trafalgar to 8th	$155				
		6th line – Nass South of 25 SR	$322				
		6th Line – Nass north of 20 SR	$321				
		UG Scott Rebuild	$250				
		U/G Main and Commercial UG Rebuild	$65				
		Sixth Line – Nass north of 20 SR		$321			
		25 SR – east of 5th		$325			
		UG Macarthur Dr rebuild		$350			
		20 SR – east of 5th			$215		
		20 SR – west of 6th			$210		
		15 SR – east of Guelph line			$365		
		Misc system renewal	$350	$450	$500	$1,300	$1,100
System Service	$6.6M	WiMAX – automate existing switches	$120				
		WiMAX – 100 Meter points	$650				
		Automated Fault Indicators – WiMAX	$175	$175			
		New Automated switches - WiMAX	$194	$250	$250	$250	$250
		New TS feeders		$450	$500	$500	$1,000
		Derry Rd – JSP to 5th			$175		
		Provision for new projects/non-Distribution System alternatives		$350	$425	$600	$250
General Plant	$2.5M	Rolling Stock	$510	$490	$500	$465	$485
Total	$48.1M						

a) Please provide a variance analysis showing which projects forecast in the last DSP were completed and at what variance to the cost estimated in that proceeding.

2.0-VECC -15

Reference: Exhibit 2, page 67

a) Please provide the project description and projected in-service date of the project associated with the $333,000 refund from Hydro One.

2.0-VECC -16

Reference: Exhibit 2,

a) Please provide the agenda for each Board of Director's meeting between 2016 and now.

2.0-VECC -17

Reference: Exhibit 2, DSP Appendix 2, PDF 308,

Project Description	This investment primarily covers the cost of building renovations within MHDI's Head office in accordance with a Strategic Facility Plan developed by Cresa. Key renovations include construction of a new Control Room (2022 investment), second floor workstations and offices to accommodate employee growth, relocation of the customer service desk and new windows.

	2023	2024	2025	2026	2027
Building Renovations	$400,000	$400,000	$400,000	$400,000	$400,000
Miscellaneous Building Capital	$119,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000
Total	$519,000	$460,000	$460,000	$460,000	$460,000

a) Are both the $400k and 119k required for the new SCADA centre renovations?

2.0-VECC -18

Reference: Exhibit 2, Attachment 2-1

a) Is the new proposed SCADA operation centre being housed in any of the disallowed space at 200 Chisholm Drive?

b) What is the total square space required for the SCADA operations?

c) What is the total square space of the disallowed office space at 200 Chisholm Drive?

d) Please provide the incremental number of FTEs (actual and proposed) since 2016 that required office space and the average square footage Milton Hydro proposes to use for those FTEs.

2.0-VECC -19

Reference: Exhibit 2,

a) What investments in its DSP and Operating Programs are specifically aimed at reducing duration of outages?

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC -20

Reference: Exhibit 3, page 12
Load Forecast Model, Rate Class Customer Model Tab
Exhibit 2, Attachment 2-2, Appendix G, page 12

a) According to Exhibit 3 (page 12) the Residential customer count forecast is based on GSAI's forecast of 750 new housing units in 2022 and 950 new housing units in 2023 within the Town of Milton. However, in the GSAI Report (Appendix G, page 12) the 750 and 950 new housing units are "ground level" housing units and do not include apartment units which are forecast to increase by 200 units per year in 2022 and 2023. Please explain why the increase in apartment units was not factored into the Residential customer count forecast.

3.0-VECC -21

Reference: Exhibit 3, pages 12-13
Load Forecast Model, Rate Class Customer Model Tab

Preamble: The. Application states:
"*Due to the COVID-19 pandemic, many General Service customers reduced demands resulting in reclassifications in August and September 2021. Since growth rates in 2021 reflect these reclassifications rather than ongoing trends, a 2012-2020 geometric mean growth rate is applied to December 2021 customer counts (rather than 2021 monthly average counts) for the GS<50 kW and GS 50 to 999 kW rate classes*".

a) .Please provide a schedule that sets out the impact of the August/September 2021 reclassification on the customer counts for the various GS classes (i.e., number of customers transferred into and out of each class).

b) Was the decline in the GS 999-4,999 class in 2021 (from 15 in January to 12 in December) all due to the August/September reclassification?

c) It is noted that for the GS<50 class the customer count for 2022 is derived by applying the forecast growth rates to the January 2022 count. Is the January 2022 value used an actual value?

a. If not, what is the January 2022 value based on and why is it used as the starting point as opposed to December 2021?

3.0-VECC -22

Reference: Exhibit 3, page 13
Load Forecast Model, Data and Rate Class Customer Model Tabs
Exhibit 7, Cost Allocation Model, Tab I6.2-Customer Data

Preamble: The Application states:
"*In 2021 many streetlighting fixtures were moved behind-the-meter. This caused a 10.1% reduction in Streetlight connection counts. This shift to behind-the-meter is not forecast to continue in 2023 and beyond so 2021 is excluded from the geometric mean growth rate applied to the Streetlight class*".

a) It is noted that the connection count for Streetlighting steadily declined over the period from May 2020 to May 2021 (see Data Tab). Is the decline all due to the change described in the Preamble?

   i. If not, what else accounted for the reduction?

b) It is noted that for the Streetlight, Sentinel and Unmetered Load classes the customer/connection counts for 2022 are derived by applying the forecast growth rates to the January 2022 count for each class. Are the January 2022 values used actual values?

   i. If not, what are they based on and why were these January values used as the starting point as opposed to December 2021?

c) Please explain what is meant by "streetlighting fixtures were move behind-the-meter" and why this resulted in a 10.1% reduction in Streetlight connection counts. As part the response, please clarify whether Streetlight load is actually "metered".

d) Please explain why this change did not impact the device:connection ratio for the Streetlight class (per CA Model, Tab I6.2), which is still 1:1 as it was in MHDI's 2016 COS Application.

3.0-VECC -23

Reference: Exhibit 3, page 13

a) Please provide a schedule that sets out the 2022 monthly customer/connection count by customer class for all months where actual values are available.

3.0-VECC -24

Reference: Exhibit 3, pages 11 and 17-18
Load Forecast Model, Residential Tab

Preamble: The Application states (page 11):
"*A set of COVID/weather interaction variables were considered to capture the incremental consumption caused by people working from home and generally staying at home due to lockdowns. These variables, "HDD COVID" and "CDD COVID" are equal to the relevant HDD and CDD variables since March 2020. The coefficients reflect incremental heating and cooling load consumed in 2020 and 2021. These variables continue to December 2022 but are reduced to 75% of HDD and CDD in all months in 2023*."

a) The Application states that the impact of the HDDCOVID and CDDCOVID variables was reduced to 75% in 2023. However, in the Residential Tab of the Load Forecast model the reduction used is 50%. Please clarify what the proposed reduction for 2023 is and update the Load Forecast as necessary.

b) Please explain the basis for the continued inclusion of the COVID/weather interaction variable in 2023 and the rationale for the "reduction" level used.

c) Did MHDI test other approaches to reflecting the impact of COVID on Residential energy use?

   i. If yes, what were the results and why were these approaches rejected?

   ii. If not, please provide a Residential regression model using an approach similar to that employed for the GS<50 class and the resulting forecast for 2023.

3.0-VECC -25

Reference: Exhibit 3, pages 10-11 and 17-18
Load Forecast Model, Residential Tab

a) With respect to the Residential model, were any other explanatory variables tested?

   i. If yes, what were they and why were they rejected for inclusion in the model?

3.0-VECC -26

Reference: Exhibit 3, pages 11 and 18-20
Load Forecast Model, GS<50 and GS>50 Tabs

Preamble: The Application states (page 11):
"*A COVID flag variable equal, to 1 from March 2020 to December 2021, was tested found to be statistically significant for the General Service < 50 kW and General Service > 50 kW classes*."

a) Contrary to the statement in the Application the COVID flag actually used in the GS<50 and GS>50 models is only set at 1.0 for the months of April and May 2020. For the month of March 2020, the balance of 2020 and all of 2021 the flag is set at 0.5. Please clarify what the proposed values of the flag for the period of March 2020 to December 2021 were intended to be and update the Load Forecast model as required.

b) It is noted that, in the Load Forecast Model, for 2022 the flag value is set at 0.38 and for 2023 the flag value is set at 0.25 for the GS<50 and GS>50 classes. Please explain the basis for using these values in the Bridge and Test years.

3.0-VECC -27

Reference: Exhibit 3, pages 10-11 and 18-20
Load Forecast Model, GS<50 and GS>50 Tabs
Load Forecast Model, Economic Tab

a) At page 11 the Application indicates that a range of economic variables were considered. However, there are no economic variables included in the GS<50 model. Please explain why none of the economic variables referenced on page 11 were included in the GS<50 model.

b) The GS>50 model includes Toronto FTEs (seasonally adjusted) as an explanatory variable. Please confirm that, out of the economic variables listed on page 11, this was the one that improved the model the most.

c) It is noted that the Toronto FTEs (seasonally adjusted) forecast for 2022 and 2023 is based on economic forecasts made by the major banks in the later months of 2021. Are there more recent forecasts for 2022 and 2023 available from the same sources and, if so, please provide the most recent forecasts from each.

3.0-VECC -28

Reference: Exhibit 3, pages 13 and 20-21
Load Forecast Model, Economic and Rate Class Energy Model Tabs

Preamble: At page 13 the Application states:
"*In 2021 many streetlighting fixtures were moved behind-the-meter. This caused a 10.1% reduction in Streetlight connection counts. This shift to behind-the-meter is not forecast to continue in 2023 and beyond*."

a) It is noted that for the GS 1,000-4,999 class the average use per customer forecast for 2022 and 2023 (9,056,779 kWh) – before any reduction for CDM – is less than the usage in all of the years 2018-2021 except for 2020 which was the first year of COVID. Why is it reasonable that the average use in 2023 will less than that in both 2019 and 2021 when: i) according the economic forecast used by MHDI in 2023 the economy has recovered to levels above those in 2019 and ii) according to the economic forecast used by MDHI economic activity in 2023 will be higher than in 2021 levels.

b) It is noted that for the Large Use class the average use per customer forecast for 2022 and 2023 (45,827,503kWh) – before any reduction for CDM – is less than the usage in all of the years 2018-2021 except for 2020 which was the first year of COVID. Why is it reasonable that the average use in 2023 will less than that in both 2019 and 2021 when: i) according the economic forecast used by MHDI in 2023 the economy has recovered to levels above those in 2019 and ii) according to the economic forecast used by MDHI economic activity in 2023 will be higher than in 2021 levels.

c) With respect to the Streetlighting class, it is noted that the 2021 connection count used in the calculation of the average consumption per connection for 2021 and hence the forecast volume for 2023 includes months where the change described in the Preamble was occurring. Does inclusion of these months result in an understatement of the average use per connection for purposes of forecasting 2023 volumes? If not, why not?

3.0-VECC -29

Reference: Exhibit 3, page 9 / Load Forecast Model, Historic CDM Tab

Preamble: At page 9 the Application states:

"*The weather normalized load forecast regressions use actual customer class kWh billed by month, plus persisting CDM, as the dependent variable in the regression models. Persisting CDM as measured by the IESO is added back to rate class consumption to simulate class consumption had there been no CDM program delivery. This is labeled as "No CDM" throughout the Load Forecast model. The effect is to remove the impact of CDM from any explanatory variables, which may capture a trend, and focus on the external factors*."

a) Please provide the IESO Reports that document/support the CDM savings from 2011 to 2020 programs as used in the Load Forecast Model for the Residential, GS<50 and GS>50 classes (i.e. the savings from 2011 to 2020 programs for the period 2011 to 2023) per the Historic CDM Tab.

b) Please indicate precisely where in these IESO Reports the annual CDM values set out in the Historic CDM Tab were taken and/or how they were derived.

c) Please explain why, in the Load Forecast Model, the annual savings were divided evenly across the 12 months as opposed to increasing on a monthly basis so as to equal the overall savings for the year.

d) Please explain why, in developing the load forecast models for Residential, GS<50 and GS>50 the savings from 2021 programs (per the CDM Forecast Tab) were not added back to the actual sales values for 2021.

e) Using the same methodology as in the CDM Forecast Tab, please undertake the following: i) calculate MHDI's contribution to the provincial 2021 CDM savings as set out in the 2021-2024 Framework for the Residential, GS<50 and GS>50 classes, ii) add these CDM savings to the 2021 CDM adjusted actuals already calculated for each class, iii) re-estimate the models for the Residential, GS<50 and GS>50 classes and iv) provide revised load forecasts for 2023 for each of the classes.

3.0-VECC -30

Reference: Exhibit 3, pages 13-14
Load Forecast Model, CDM Forecast Tab

Preamble: At page 13 the Application states:
"*On December 20, 2021, the OEB issued a report Conservation and Demand Management Guidelines for Electricity Distributors which provided updated guidance on the role of CDM for rate-regulated LDCs. Milton Hydro has reviewed these guidelines as it derived a manual adjustment to the load forecast. This CDM adjustment has been made to reflect the impact of CDM activities that are expected to be implemented through the 2023-2027 rate period*".

At page 14 the Application states:
"*Average cumulative CDM savings from programs implemented in 2021 to 2024 persisting to each year from 2023 to 2027 are calculated for each 2021-2024 CDM Framework program*."

At page 14 the Application also states:
"*Average provincial cumulative CDM savings in 2023 to 2027 is then attributed to rate classes based on Milton Hydro's historic allocation of the 2021-2024 CDM Framework programs and similar programs, and the judgement of Milton Hydro's consultants IndEco and Elenchus*".

a) Please provide a copy of the IESO's 2021-2024 Conservation and Demand Management Framework Plan used to derived MMHDI's CDM savings from 2021-2024 Programs.

b) Please provide reference as to where, in the Plan, it states that the savings will persist until 2026 (per the CDM Forecast Tab).

c) Please provide the data regarding MDHI's "historic allocation of 2021-2024 CDM Framework programs" referenced in the Preamble and provide the source of the data.

d) Please provide the analysis/calculations supporting the percentages used for MHDI's share of the provincial savings for each customer class (e.g., 0.5% for Residential).

e) Please provide the calculation of the growth rates used to determine the "in year energy savings" for 2025-2027 per the CDM Forecast Tab (Row 21).

As part of the response, please copies of any references/sources for the data used.

f) Please explain more fully why is it is appropriate to include in the calculation of the CDM adjustment for 2023 savings from CDM Programs which are to be implemented in 2024-2027.

g) If savings from CDM programs implemented after 2023 are to be incorporated in the load forecast please explain why the impact of future growth in customer/connection counts and volumes after 2023 should not also be reflected in the load forecast for 2023.

h) Please recalculate the 2023 CDM adjustment for each class only using the savings from programs implemented in 2021-2023.

i) At page 14, reference is made to using the 2019 Conservation Achievable Potential Study as a source for future CDM savings. Has the IESO formally included the savings estimates from this Study in its most recent load forecast as set out in its 2021 APO?

    i. If yes, please provide the appropriate references.

3.0-VECC -31

Reference: Exhibit 3, pages 37-39

a) With respect to USOA#4210 (Rent from Electric Property) it is noted that the percentage increases in revenues for 2023 over 2022 varies widely as between Cogeco, Rogers and Bell. Please explain why this is the case and how the 2023 revenues from each company were determined.

b) What is the basis for the increase in USOA#4390-Miscellaneous Revenues to $126,000 in 2022 and why is it just for the one year?

4.0 OPERATING COSTS (EXHIBIT 4)

4.0 -VECC -32

Reference: Exhibit 4, page 24

Table 4-9 Underground Locates

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Underground Locates	$380,000	$358,200	$378,024	$373,373	$383,562	$338,981	$379,451	$368,598	$437,230	$443,788

a) Please explain how the costs of locates is calculated for historical periods and the basis of the estimates for the Bridge and Test years.

b) What is the current cost of locates in 2022 (please specify up to what date)?

4.0 -VECC -33

Reference: Exhibit 4, pages

Table 4-14 Customer Premise

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Customer Premise	$258,653	$271,661	$302,193	$382,742	$359,653	$418,959	$513,419	$374,771	$400,418	$576,600

a) Please explain how the cost of customer premise services was calculated for the historical years 2016-2021.

b) Please provide the number of service requests for each year 2016 to 2021 and the forecast calls for 2021 and 2022

c) Please provide the actual cost of customer premise service calls to date in 2022.

4.0 -VECC -34

Reference: Exhibit 4, page 57

a) MHDI is proposing to increase its community relations budget by about 10x the past average amount. Please describe how the expansion of this program (and the cost) was included in the customer engagement exercise.

4.0 -VECC -35
Reference: Exhibit 4, Appendix 2-JA / page 78

a) Are any costs of this application recorded in Appendix 2-JA or 2-JC for any period prior to 2023? Specifically, is the $218,142 shown for 2021 actuals in Table 4-38 also included in either or both Appendices?

4.0 -VECC -36
Reference: Exhibit 4, page 63

a) Was the CDM specialist whose role was eliminated offered a new position within MHDI?

4.0 -VECC -37
Reference: Exhibit 4, page 67

Table 4-32 Management Consulting and Professional Fees

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Management Consulting & Prof. Fees	$304,857	$305,643	$288,754	$364,376	$540,105	$572,212	$916,575	$497,944	$531,984	$600,043

a) MHDI proposes to increase its employee compliment by about 28% as compared to that in 2016. The increase in FTEs which has a significant impact on ratepayers' costs, includes an enhanced IT department (Director, IT & Client Services) and enhanced Corporate Finance department, and enhanced and Executive and Board expenses that will increase from approximately $1 million in 2016 to $2 million in 2023 and include 2 new Vice-President roles. Given all of these (costly) resource additions in administrative and executive functions please explain the rationale for the continuation of Management Consulting and Professional Fees.

b) Please provide the fee invoices for all services provided by Milton HydroHoldings in 2016 through 2021.

c) Please provide the contracts for services for fees charged by Milton Hydro Holdings for the 2016-2021 period.

4.0 -VECC -38
Reference: Exhibit 4, page 68

a) If MHDI is a member of the EDA please provide the annual fees for each year 2016 through 2023 (forecast).

4.0 -VECC -39
Reference: Exhibit 4, page 70

"*2023 Test Year expenditures are $333,658 higher than 2016 OEB Approved, primarily due to: (i) cost increases of $81,910 associated with annual inflation; (ii) $54,000 for annual software maintenance expenditures to support technology investments during the rebasing period (omni channel platform, process automation tools, HRIS and payroll systems); (iii) $50,000 for the acquisition of a cloud based compliance reporting and management solution to deliver statutory, management and regulatory more productively; (iv) $38,000 for higher software maintenance costs on the Customer Information System ("CIS"); (v) $37,000 for increased software maintenance costs related to the legacy Financial Management System; (vi) $34,000 for higher license costs for Engineering systems and maintenance; (vii) increases in licenses related to office products and cyber corresponding to increased headcount and rates; (viii) $32,000 for increased in server support application expenditures; and (ix) $30,000 for services supporting network and communication technology for delivering Advanced Metering Infrastructure ("AMI")."*

a) For each of (i) to (ix) please provide the vendor notification of the maintenance cost increase for 2022 and 2023.

4.0 -VECC -40
Reference: Exhibit 4, Appendix 2-M

a) Appendix 2-M shows the Board Annual Assessment cost in years 2016 through 2022 as $93,000. What were the actual annual assessment charges from the Board for each of those years?

4.0 -VECC -41
Reference: Exhibit 4, page 94

"*Milton Hydro experienced a 100% turnover of its entire Senior 1 Management Team (SMT) between August 2020 and January 2022. A new CEO was hired in August 2020, a new Director, Regulatory Affairs hired in September 2020, a new CFO hired in February 2021, and a new VP Distribution Services was hired in January 2022.*
Milton Hydro engaged a 3rd party consultant in 13 2021 to undertake a Resource Optimization Review (Attachment 4-3)."

a) Were any of the executives or senior managers who left the Utility (terminated or retired on own volition) interviewed by the workforce consultant?

4.0 -VECC -42
Reference: Exhibit 4, pages 95-

a) Please provide a list of all vacant positions at MHDI. Please include how long the position has been vacant and the current status of recruitment.

4.0 -VECC -43
Reference: Exhibit 4, Appendix 2-K

a) Please amend Table 4-47 (Appendix 2-K) to show the total amount of capitalized and expensed compensation for each year.

4.0 -VECC -44
Reference: Exhibit 4, Appendix 2-K

"*In 2021, Milton Hydro eliminated its Director Engineering position and replaced it as a VP Distribution Services position. This was accomplished with no impact to salaries and/or benefits*."

a) Please provide the salary bands for the former Director position and the new VP Distribution position.

b) Is the VP position eligible for performance incentives? If so what is the maximum performance benefit attainable?

c) Was the former Director position eligible for performance incentives?

4.0 -VECC -45
Reference: Exhibit 4, pages 101-

a) Please provide the job descriptions/responsibilities for (1) VP Customer Experience; (2) Process Improvement Officer and (3) Manager People & Culture.

4.0 -VECC -46
Reference: Exhibit 4, pages 116 / Appendix 2-JC

"*In 2022, Milton Hydro will hire its first dedicated in-house Manager H&S, eliminating the cost of contracting out, resulting in a slight net savings to Milton Hydro Customers*."

a) Please identify the programs in Appendix 2-JC where savings occur in 2023 as a result of bringing in-house the Manager of H&S.

4.0 -VECC -47
Reference: Exhibit 4, pages 116 / Appendix 2-JC

a) A number of the new positions are replacing formerly outsourced roles (e.g., Manager of H&S, Engineering Technologist etc.). Please identify all new positions since 2016 which are replacing previously outsourced roles.

b) Please identify the amount of the reduction due to the removal of these outsourced roles in each of 2022 and 2023 and identify the Appendix 2-JC program where the savings occur.

4.0 -VECC -48
Reference: Exhibit 4, pages 123-

"…*in 2022 Milton Hydro will review each management and non-union role, against the Korn Ferry (formerly Hay Group) Job Evaluation ("JE") methodology*."

a) Does the 2023 compensation forecast anticipate any changes to compensation that might result from the compensation review that Milton Hydro is undertaking?

4.0 -VECC -49
Reference: Exhibit 4, pages 126-

a) Please explain how employee incentives are related to outage and outage durations and specifically outages due to defective equipment.

4.0 -VECC -50
Reference: Exhibit 4, pages 126-

a) MHDI cost-benefit analysis for an in-house SCADA control system relies significantly on improvements in reliability. Please explain how system reliability changes will be used to calculate actual benefits once the control centre is in operation.

4.0 -VECC -51
Reference: Exhibit 4 Attachment 4-1, page 4, Attachment 4-2, page13

a) For each of the Utilities shown in Table 1 with in-house control rooms please provide the annual operating costs for the centre (as found for example in a prior Board cost of service application).

b) For each Utility shown in Table 1 as having an in-house SCADA centre what was the number of centre operators and supervisors employed by that Utility?

c) Which of the Utilities shown in Table 1 with an in-house control room operate their facility 24/7?

d) Please identify any of the Utilities in Table 1 with an in-house control room that share those facilities with another utility.

4.0 -VECC -52
Reference: Exhibit 4, Attachment 4-1, Table 6, Attachment 2 Section 3.2

Table 6: Comparison of Cumulative Costs and Savings

	Option 1: 24/7 in house	**Option 2: In-House Day, Outsourced After Hours**	**Option 3: Outsourced 24-7 coverage**
One Time Costs	$512,000.00	$555,500.00	$117,500.00
Annual Costs	$1,532,975.00	$774,000.00	$1,633,100.00
Potential Annual Customer Benefit	$1,235,064.39	$0	$1,235,064.39
Net Year 1	**($809,910.61)**	**($1,329,500.00)**	**($515,535.61)**
Cumulative Cost 5 Years	$8,176,875.00	$4,425,500.00	$8,283,000.00
Cumulative Savings 5 Years	$6,175,321.95	$0	$6,175,321.95
Net Year 5	**($2,001,553.05)**	**($4,425,500.00)**	**($2,107,678.05)**
Cumulative Cost 10 Years	$15,841,750.00	$8,295,500.00	$16,448,500.00
Cumulative Savings 10 Years	$12,350,643.90	$0	$12,350,643.90
Net Year 10	**($3,491,106.10)**	**($8,295,500.00)**	**($4,097,856.10)**

a) Please show numerically how the amount of "Potential Annual Customer Benefit" of $1,235,064.39 is derived by explaining the assumption for each variable - specifically:
    i. how the "Without" and "With Improvement" values in Attachment 4-2 Table 17 are derived;
    ii. showing the value assigned to reduction in outages and outage restoration for each customer class;
    iii. showing the basis for assuming any improvement in outage or outage duration in moving from outsourced (existing) to in-source SCADA control centre

b) Please provide all the variable inputted into the ICE model to perform the calculation supporting $1,235,064.39 in benefits

4.0 -VECC -53
Reference: Exhibit 4, Attachment 4-1, Table 3, Appendix 2-JC

c) Please reconcile the total annual operating costs of $1,586,275 shown in Table 3 with the Control Room Services costs of $1,155,897 shown for 2023 in Appendix 2-JC (OM&A Programs Table).

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

5.0-VECC-54
Reference: Exhibit 5, page 7

"*Milton Hydro is proposing the following new financing arrangements with TD:*
- *issuance of $8,000,000 in fixed committed reducing term loan in 2022 for financing incremental balance sheet growth and debt maturities in two tranches; and*
- *issuance of $14,934,210 in interest only bearing loans in 2022 to refinance promissory note with the Town of Milton*."

a) Please identify which rows in Table 5-13 (Appendix 2-OB 2023) make up the $8 million TD loan discussed above.

b) Please identify any 2022 - 2023 loans which have not yet been negotiated.

c) Is it MHDI's proposal to utilize the 3.49% as the cost rate for any loan which has not been negotiated prior to the completion of this proceeding?

5.0-VECC-55
Reference: Exhibit 5, page 7

"*In 2022, Milton Hydro retired the promissory note with the Town of Milton with a short-term revolving facility*."

a) Please provide the promissory note referred to above.

b) Please explain the timing of the retirement of this note and specifically the ability of MHDI to retire the note earlier.

6.0 CALCULATION OF REVENUE DEFICIENCY/SURPLUS (EXHIBIT 6)

N/A

7.0 COST ALLOCATION (EXHIBIT 7)

7.0-VECC-56

Reference: Exhibit 7, page 3

Preamble: The Application states:
"*Milton Hydro has used the 2016 COS version of the Model and submitted the revised Model to reflect 2016 Test Year costs, customer numbers and demand values. The 2016 demand values are based on the weather normalized load forecast used to design rates. Milton Hydro has developed weighting factors as outlined below based on discussions with staff experienced in the subject area*"

a) The paragraph referenced in the Preamble makes a number of references to 2016. In each case, please confirm whether 2016 is the correct year to be referenced.

7.0-VECC-57

Reference: Exhibit 7, page 3

Preamble: The Application states:
"*The analysis for the Services weighting factor included a review of Milton Hydro's installation and cost recovery for Services as set out in Milton Hydro's Conditions of Service Section 3.3 General Service (Above 50 to 1000 kW) and Section 3.4 General Service (Above 1,000 KW). Milton Hydro has costs in USoA 1855 – Services for Residential and General Service <50 kW customers only. Milton Hydro has calculated the costs to provide a secondary service to either a Residential customer or a General Service <50 kW customer to be the same. All customer classes >50 kW install and pay for their own services. Milton Hydro does not collect capital contributions on these services and does not own or perform any maintenance work on the customer owned services*"

a) The referenced paragraph explains that all customer classes >50 kW install and pay for their own services. However, there is no explanation as to why no Services costs are allocated to the Streetlighting, Sentinel or Unmetered Load classes where connected loads are below 50 kW. For each of these three classes please explain who pays for the Services assets required to connect to MHDI's system and where in the Conditions of Service these requirements are set out.

7.0-VECC-58

Reference: Exhibit 7, pages 4-5

Preamble: The Application states (page 4):
"*Billing and collecting costs comprise billing software, Canada post charges, and effort from Milton Hydro's Billing, Collections, and Customer Service departments. In determining the weighting factors for Milton Hydro staff, supervisors were asked to consider their staff efforts required for the Billing, Collecting, and Customer Service departments. In general, equal weight was given to each customer/bill with the exception of Olameter cost, Collections Department costs, and Customer Service Department costs*."

a) Are any of MHDI's customers subject to e-billing?

   i. If yes, please provide the number of customers in each class that are currently subject to e-billing (i.e., use the last month for which actual customer counts for each class are available).

   ii. If yes. how has the use of e-billing been reflected in the bill printing cost and Canada post costs allocated to the customer classes?

b) Please provide a schedule that sets out the derivation of the billing and collecting weights set out in Table 7-2.

7.0-VECC-59

Reference: Exhibit 7, Cost Allocation Model, Tabs I6.1, I6.2 and I8

a) In Tab I6.1 a portion of the billing demand for the GS 50-999 class is shown as receiving the line transformer allowance. Similarly, in Tab I6.2 the GS 50-999 customer counts for Line Transformer and Secondary are less than the count for Primary. However, in Tab I8 the GS 50-999 class' 4NCP values for Primary, Line Transformer and Secondary are all the same. Please reconcile.

7.0-VECC-60

Reference: Exhibit 7, page 10

Preamble: The Application states:
"*As described in section 8.13 of Exhibit 8, the Sentinel Light rate change will be implemented over two years to avoid total bill impacts that exceed 10%. Milton Hydro proposes to increase the Sentinel Lights Revenue to Cost Ratio to 80% in 2024, with a corresponding decrease to the GS 1,000 to 4,999 kW from 118.97% to 118.30%.*"

a) For 2023 MHDI is proposing to move the R/C ratio for the Sentinel class further away from 1.0. What would be the 2023 total bill impact for the Sentinel class if the R/C ratio was held at the status quo value of 76.93%?

b) For 2023 MHDI is proposing to move the R/C ratio for the Sentinel class further away from 1.0. What would be the 2023 total bill impact for the Sentinel class if the R/C ratio was increased to 80%?

8.0 RATE DESIGN (EXHIBIT 8)

8.0-VECC-61

Reference: Exhibit 8, pages 5-6
Cost Allocation Model, Tab O2
Report of the Board – Application of Cost Allocation for Electricity Distributors (EB-2007-0667), page 12

a) With respect to Table 8-5, please confirm that the values in the last column (far right) represent the greater of: i) the class' current fixed rate and ii) the value from Tab O2 for the class' Customer Unit Cost per month – Minimum System with PLCC Adjustment.

b) Please confirm that for the GS 50-999, GS 1,000-4,999, Large Use and Streetlight classes the existing fixed charge is above the value for the class' Customer Unit Cost per month – Minimum System with PLCC Adjustment and MHDI is proposing to increase the fixed charge further in 2023.

    i. If yes, please explain how these proposed increases are consistent with the OEB's policy with respect to monthly fixed charges as set out in its EB-2007-0667 Report.

8.0-VECC-62

Reference: Exhibit 8, page 8
Exhibit 3, page 26

Preamble: The Application states (Exhibit 8, page 8):
"*Milton Hydro has a Minimum Distribution Charge - per kW of maximum billing demand in the previous 11 months. This rate is a $/kW charge applicable to the GS 50 to 999 kW, GS 1,000 to 4,999 kW, and Large Use rate classes*."

a) For the period 2016-2021 did MHDI collect any revenue based on the application of its Minimum Distribution Charge?

    a. If yes, please provide a schedule setting out the amounts collected in each year by customer class.

    b. If yes, where in Table 3-17 (Exhibit 3) are these revenues reported?

    c. If yes, is there any revenue from the Minimum Distribution Charge included in the 2023 COS Application and, if so, where is it accounted for?

8.0-VECC-63

Reference: Exhibit 8, pages 8-9
RTSR Workform, Tab 3 (RRR Data) and Tab 5 (Historical Wholesale)

a) Is the usage data set out in Tab 3 and Tab 5 all based on the same historical period?

8.0-VECC-64

Reference: Exhibit 8, page 10
Exhibit 3, page 8

Preamble: The Application states (Exhibit 8, page 12):
"*Peak demands are forecast by Milton Hydro's Engineering group based on planned projects and Milton's regional load growth plan*."

a) Please provide the 2023 peak demand forecast for MHDI as prepared by Milton Hydro's Engineering group broken down in sufficient detail to show the peak demands for Hydro One and Oakville Hydro per Table 8-11.

b) Is the peak demand forecast prepared by Milton Hydro's Engineering group derived so as to be consistent with the 2023 load forecast set out in Exhibit 3?

   i. If yes, please explain how this done.

   ii. If not, please provide more details regarding how the forecast is prepared.

c) It is noted (Exhibit 8, page 10) that the forecast 2023 Total Host Billed Demand (445,993 kW) is greater than in any of the historical years 2018-2021. However, the total forecast kWhs for 2023 (903,810,994 kWh) is less than that in any of the historical years 2018-2021 (per Exhibit 3, page 8). Please explain why this is the case?

8.0-VECC-65

Reference: Exhibit 8, pages 10 and 13-14

a) At page 10 MHDI indicates that it pays LV charges to Hydro One and Oakville Hydro. However, at pages 13-14 MHDI indicates that it only purchases power from the IESO, Oakville Hydro and embedded generators. Please explain the circumstances that give rise to MHDI paying Hydro One LV charges but not purchasing power from Hydro One.

8.0-VECC-66

Reference: Exhibit 8, page 16
Tariff Schedule and Bill Impact Model, Tab 6 – Bill Impacts

a) In Table 8-15, please confirm that the Distribution Bill Impacts shown for Streetligting and Sentinel are reversed.

DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0 –VECC -67

Reference: Exhibit 9, page 15

a) For the OEB Cost Assessment Variance sub-account (1508) please show how the annual amount of variance calculated. Specifically explain how the variance calculation adjusts for the annual IRM increase in rates.

End of document