Espanola Regional Hydro Distribution Corporation
598 Second Avenue
Espanola, ON P5E 1C4

March 25, 2021

Delivered by Email & RESS
Ms. Christine Long, Registrar
Ontario Energy Board
P.O.Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Espanola Regional Hydro Distribution Corporation ("ERHDC") 2021 Cost of Service Application ("Application")
OEB File No.: EB-2020-0020
ERHDC's Interrogatory Responses

Pursuant to Procedural Order No. 1 dated February 11, 2021, please find enclosed ERHDC's Interrogatory Responses in this proceeding.

Sincerely,

Tyler Kasubeck

Tyler Kasubeck, Contract Services, Espanola Regional Hydro Distribution Inc.
PUC is the contract managed service company for Espanola Regional Hydro Distribution Corporation
Email: tyler.kasubeck@ssmpuc.com Phone: 705-759-3009

cc : John Vellone, Borden Ladner Gervais LLP

Espanola Regional Hydro Distribution Corporation

EB-2020-0020

Responses to Interrogatories

Filed: March 25, 2021

Table of Contents

Espanola Regional Hydro Distribution Corporation.
INTERROGATORY RESPONSES

Ontario Energy Board Staff Interrogatories

Staff-1 – Updated Revenue Requirement Workform (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, as applicable, that reflects the interrogatory responses, including an updated Tariff Schedule and Bill Impact model for all classes at the typical consumption/demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.).

Response:

Espanola Hydro has made updates to the following models which are filed with this application in live excel version. The specifics of the updates are also outlined under the respective model updates below.

1. ERHDC_2021_Filing_Requirements_Chapter2_Appendices_IRR_Response_20210325
    a. Appendix 2-AA Capital Projects
        - Staff 10, CCC 9b and VECC 13 update for 2020 actuals
        - CCC9a update 2016 data
    b. Appendix 2-AB Capital Expenditures
        - Staff 10, CCC 9 and VECC 13 update for 2020 actuals
        - Staff-9 correction to 2016 capital expenditures
        - CCC11 update to include 2016 and 2020 data
    c. Appendix 2-BA Fixed Assets Continuity
        - Staff 10, CCC 9b and VECC 13 update for 2020 actuals
    d. Appendix 2-C Depreciation Expenses

- Staff 10, CCC 9b and VECC 13 update for 2020 actuals

e. Appendix 2-H Other Revenue
   - VECC 20d – update to pole attachment revenue calculation
f. Appendix 2-JA OM&A Summary Analysis
   - VECC 21 – include 2020 actuals
g. Appendix 2-JB OM&A Cost Drivers
h. Appendix 2-JC OMA Programs
   - VECC 21 – include 2020 actuals
i. Appendix 2-OB Debt Instruments
   - VECC-29 update to include more recent debts
   - VECC 32 updated debt and start dates of all loans
j. Appendix 2-ZA Com. Exp Forecast
   - Staff 7a – Cost of power rate updates
k. Appendix 2-ZB Cost of Power
   - Staff 7b – Change in COP calculation and update to 21.2% OER Rebate
   - Staff 35 – low voltage rates

2. ERHDC_2021_Cost_Allocation_Model_20210325
   a. I3 TB Data
      - 2020 Actual incorporated which changed the average fixed assets
      - Staff7c – Updated Working Capital Allowance calculation
   b. I4 BO Assets
      - 2020 Actuals incorporated which changed the average fixed assets
   c. I5.2 Weighting Factors
      - Staff 32 – Change in 1855 Service Weighting Factors

3. ERHDC_2021_DVA_Continuity_Schedule_20210325
   a. 2a. Continuity Schedule
      - OEB Staff 40 – reconciliation of account 1588

4. ERHDC_2021_RTSR_Workform_20210325
   a. 4. UTRs and Sub-Transmission
      - Staff 34 update to Hydro One Sub-Transmission rates

5. ERHDC_2021_Rev_Reqt_Workform_20210325
   a. As per tab 14. Tracking sheet, the Revenue Requirement Workform has been updated to reflect the changes noted in the above models. Specifically, the following has caused changes to the Revenue Requirement Workform.
      1. 2020 Actuals have been incorporated
      2. Miscellaneous revenue has been updated to remove $65,000 in DVA interest income and an update to the pole attachment revenue calculation.

3. The 1855 Service weighting factors in the cost allocation model changed.

6. ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_20210325
   a. Staff-36 Separation of the Wholesale Market Service Rate and Capacity Based Recovery Rate.

Staff-2 – Return on Equity

Reference: Exhibit 1, Pages 13-14, 65

Preamble:

Espanola Hydro provided the following table summarizing its achieved return on equity (ROE) over the past six historical years.

Year	2014	2015	2016	2017	2018	2019
% Deemed	9.12	9.12	9.12	9.12	9.12	9.12
% Achieved	28.00	15.91	6.29	2.45	4.12	-9.46

In the reference, Espanola Hydro explains that:

- 2014-2015 ROE was high due to rate mitigation measures implemented from the 2012 cost of service
- 2016-2019 ROE was low due to unfavourable distribution revenue and from not reaching the consumption levels projected in its 2012 cost of service application
- 2019 ROE was especially low due to higher administrative costs associated with the sale of Espanola Hydro

OEB staff notes that Espanola Hydro's ROE between 2016-2018 (i.e. the years without any unique circumstances) fluctuated significantly.

Question:

(a) Please provide an analysis showing the factors driving the fluctuations in Espanola Hydro's achieved ROE in the historical years.

Response:

Overall, from 2014 to 2019 Espanola Regional Hydro Corporation ("ERHDC") has seen a significant declining trend in Net Income due to decreasing distribution revenues and rising costs. Total rate base has gone up 5% on average over that last 4 years. The following outlines the factors driving the fluctuations in the Net Income of Espanola Hydro's achieved ROE in the historical years:

2014 Return on Equity 28%

The following is the comparison between the 2014 actual return and the approved return with variance explanations.

Table Staff-2 – 2014 Actual Return vs Approved Return

2014 ROE Espanola
Earning Analysis for the purpose of the ROE

Note: Materiality threshold was $50,,000 in the 2012 CoS rate proceeding.

Particulars	Per 2012 CoS Board Decision (A)	Per 2014 AFSs & RRR 2.1.5.6 (B)		Difference $ (B-A)	Diff %	Questions	Response
Distribution revenue	$1,636,303	Distribution revenue	$1,886,494	$250,191	15%	Please explain the variance with the approved the distribution revenue besides the rate riders	of the $250,191 variance , $221,800 was due to Rate riders for Foregone Revenue, LRAM and Residual Smart meters . Distribution Volumetric Revenue was up $41,200 due to higher consumption for Residential customers.
Other revenue	$142,399	Other revenue less non-rate regulated items	$132,134	($10,265)	-7%		Audited FS include $5,528 for Street lights net income. Total Other Revenue should be $137,662. Remaining favorability is due to higher late payments $10M offset by lower misc services/jobbing revenue $5,400
Total Revenues	**$1,778,702**	Total Revenues	$2,018,628	$2,018,628			
O & A expenses		**O & A expenses**					
Tree Trimming	$37,500	Tree Trimming	$ -	($37,500)		Please explain the variance with the approved OM&A expense besides the lineman vacancy and the tree trimming expense savings.	Tree Trimming on Bass Lake Road required immediate attention. In the CoS there was $150,000 planned for this specific line clearing spread over 4 years, or $37,500 per year . The line was cleared in 2012 and all expenses were recorded in actuals in 2012. $0, 2014 for this planned clearing. In addition 2014 regular line clearing was down versus budget
Lineman Salary /Benefits 12 months	$ 107,248	Lineman 6 months	$ 53,524	($53,724)			Actuals $53, 624 lower due to half year vacancy
Regulatory	$ 34,375	Regulatory	$ 21,045	($13,330)			One Time Regulatory Expenses lower than anticipated. These one time expenses include preparation of an asset managemnt plan, consultants for LRAM and 1562 PILS determination.
Pension and Benefits	$ 20,000	Pensions and Benefits	-$ 12,646	($32,646)			in 2014 there was a reduction in the value of Post Retirement liabilities and resulted in income of $12,646 vs planned expense of $20,000
Management Salary Training	$ 12,000		$ -	($12,000)			2012 CoS planned for the retirement of a key senior manager. To ensure a smooth transition the new manager was hired prior to the retirement. Increase in salary was estimated to be $48,000 and was spread over 4 years- $12, 000 per year. CoS Salaries were therefore $12,000 higher than 2014 which did not have this expense.
Other OM&A Expenses	$1,149,001	OM&A Expenses	$ 1,140,197	($8,804)	-1%		Remaining variance immaterial at 1%
Total OM & A	**$1,360,124**		**$1,202,120**	**($158,004)**			

Ammortization									
			IFRS vs CGAAP		($29,483)	($29,483)			
Other Amortization/Depreciation		$146,055	Other Amortization/Depreciation		$123,285	($22,770)	-16%	Did Espanola change the depreciation policy in 2012 CoS? If not, when did Espanola change the depreciation policy (2012 or 2013)?Please explain the variance with the approved amortization expense.	Espanola did not change the depreciation policy in 2012 CoS. Variance is explained by reduction in expense of $ 29,483 due to IFRS vs CGAAP adjustment per Sept 2012 Decision Remaining variance was due to the due to the change in the Asset Life. Asset Life Changes were done in 2013.
					$ -				
Total Amortization/Depreciation		**$146,055**	**Total Amortization/Depreciation**		**$93,802**	**($52,253)**			
Property Taxes			Property Taxes		0				
Capital Taxes		$ -	Capital Taxes		0	$ -			
Income Taxes (Grossed up)		$9,316	Income Taxes		$ 101,935	**$92,619**	**994%**	Espanola responded "No" for Tax adjustment question. However, it is noted that there is significant difference between the PILs in the rates and actual PILs. Please explain the reason of the difference and answer the questions for the tax adjustments in Section C of the questionnaire	In the Cos the Net income for **tax purposes** is $50,789 vs accounting income before taxes of $164,164. 2014 income Taxes of $101,935 is based on taxable income of $592,000.
Deemed Interest Expense		$108,360	**Actual Interest Expense**		$67,231	($41,129)			
Total Expenses		**$1,623,855**	Total expenses including deemed interest		**$1,465,088**	-$ 61,820	-4%		
		$154,847			$ 553,540	($553,540)			
			Interest adjustment per RRR 2.1.5.6		$28,393				
Net Income (Return on Deemed Equity)		**$154,847**	**Net Income - adjusted for after-tax deemed interest**		**$525,147**	**$370,300**	**239%**		
Controllable Expenses	$1,360,124		Controllable Expenses	$1,300,675	Per RRR 2.1.5.6	($59,449)			
Cost of Power	$6,226,613		Cost of Power	$7,153,891		$927,278			
Working Capital Base	$7,586,737		Working Capital Base	$8,454,566		$867,829			
Working Capital Rate %	15%		Working Capital Rate %	15%					
Working Capital Allowance		$1,138,010.55	Working Capital Allowance		$1,268,184.90	$130,174			
Gross Fixed Assets (average)	$7,947,795		Gross Fixed Assets (average	$8,421,536		$473,741			
Accumulated Depreciation (average)	($4,841,071)		Accumulated Depreciation (average)	($5,000,765)		($159,695)			
Net Fixed Assets (average)		$3,106,725	Net Fixed Assets (average)		$3,420,771	$314,046			
Total Rate Base		**$4,244,735.05**	**Total Rate Base**		**$4,688,955.40**	**$444,220**			
Regulated Deemed									
Deemed ROE		**9.12%**	**Achieved ROE**		**28.00%**	**18.88%**			

2015 Return on Equity 15.91%

Below is the 2015 calculation of Return on Equity at 15.91% compared to the Return on Equity calculation excluding the revenue associated with the LRAM and Stranded Meter Recovery. Excluding these recoveries the Return on Equity is 11.42% which is within 300 basis points of the deadband.

Table Staff-2 – 2015 ROE Calculations

		2015 as Filed	2015 Adjusted for Rate Riders
Regulated net income (loss), as per RRR 2.1.7		$439,211.87	$439,211.87
Rate Riders for LRAM and Stranded Meter Recovery included in Revenue			-$87,119.68
Regulated net income (loss), as per RRR 2.1.7		$439,211.87	$352,092.19
Adjustment items:			
Non-rate regulated items and other adjustments (Appendix 1)		$4,329.00	$4,329.00
Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)		$0.00	$0.00
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB			
Non-recoverable donations (Appendix 2)		$100.00	$100.00
Net interest/carrying charges from DVAs (Appendix 3)		-$15,845.90	-$15,845.90
Interest adjustment for deemed debt (Appendix 4)		-$55,391.20	-$55,391.20
Adjusted regulated net income before tax adjustments		$372,403.77	$285,284.09
Add back:			
Future/deferred taxes expense		$0.00	$0.00
Current income tax expense (Does not include future income tax)		-$107,852.00	-$107,852.00
Deduct:			
Current income tax expense for regulated ROE purposes (Appendix 6)		-$44,184.68	-$44,184.68
Adjusted regulated net income		$308,736.45	$221,616.77
Deemed Equity			
Rate base:			
Cost of power		$7,413,565.57	$7,413,565.57
Operating expenses before any applicable adjustments		$1,371,661.77	$1,371,661.77
Other Adjustments:			
Adjusted operating expenses		$1,371,661.77	$1,371,661.77
Total Cost of Power and Operating Expenses		$8,785,227.34	$8,785,227.34
Working capital allowance % as approved in the distributor's last CoS Decision and Order		15.00%	15.00%
Total working capital allowance ($)		$1,317,784.10	$1,317,784.10
PP&E			
Opening balance - regulated PP&E (NBV) (Appendix 5)		$3,483,250.00	$3,483,250.00
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)		$3,581,344.94	$3,581,344.94
Average regulated PP&E		$3,532,297.47	$3,532,297.47
Total rate base		$4,850,081.57	$4,850,081.57
Regulated deemed short-term debt % and $	4.00%	$194,003.26	$194,003.26
Regulated deemed long-term debt % and $	56.00%	$2,716,045.68	$2,716,045.68
Regulated deemed equity % and $	40.00%	$1,940,032.63	$1,940,032.63
Regulated Rate of Return on Deemed Equity (ROE)			
Achieved ROE%		15.91%	11.42%
Deemed ROE% from the distributor's last CoS Decision and Order		9.12%	9.12%
Difference - maximum deadband 3%		6.79%	2.30%
ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)		Over-earning	Within 300 basis points deadband

2016 Return on Equity 6.29%

2015 vs 2016

Overall, 2016 saw a significant drop in ROE from 15.91% to 6.29% which was attributed to a drop in Net Income. The following outlines the specific areas within Net Income that were affected.

Table Staff-2 – 2015 vs 2016 Factors Affecting Net INcome

	2015	2016	2016 vs 2015
Revenue	$1,873,192	$1,776,207	-$96,985
OM&A	$1,343,414	$1,387,714	$44,300
Depreciation	$88,254	$129,660	$41,406
Interest	$84,260	$165,261	$81,002
Taxes	-$107,752	-$24,151	$83,601
	$1,408,175	$1,658,483	$250,308
Non-LDC income (CDM, S/L)	$2,443	$1,360	-$1,083
Net Income	$467,460	$119,084	-$348,376

- Distribution revenues dropped by $86,000 mainly as a result of expiring rate riders in the amount of $49,000 and an approximate 3% variance in regular distribution revenue.
- There was an increase in OM&A of $44,300 or 3%
- Depreciation increased by 41,000 from an increase in depreciation expenses on Poles and OH Lines and Feeders.
- Interest increased by 81,000 from financing the rebuild of a substation approved as part of ERHDC’s 2014 IRM/ICM application.
- The 2015 tax credit was reduced by $53,601

2016 vs 2017

In 2017, ERHDC saw a further reduction in ROE from 6.29% to 2.45% due to the following factors.

Table Staff-2 – 2016 vs 2017 Factors Affecting Net Income

	2016	2017	2017 vs 2016
Revenue	$1,776,207	$1,724,269	-$51,938
OM&A	$1,387,714	$1,401,624	$13,910
Depreciation	$129,660	$144,902	$15,242
Interest	$165,261	$166,044	$783
Taxes	-$24,151	-$63,196	-$39,045
	$1,658,483	$1,649,374	-$9,110
Non-LDC income (CDM, S/L)	$1,360	$1,929	$569
Net Income	$119,084	$76,824	-$42,260

- Net Income fell by $42,260 due mainly to a reduction in distribution revenue
- Distribution revenues dropped by $51,938 mainly as a result of expiring rate riders in the amount of $38,000 and a small variance in regular distribution revenue.

<u>2017 vs 2018</u>

Overall, 2018 saw a slight increase in ROE from 2.45% to 4.12%.

Table Staff-2 – 2017 vs 2018 Factors Affecting Net Income

	2017	2018	2018 vs 2017
Revenue	$1,724,269	$1,785,464	$61,195
OM&A	$1,401,624	$1,412,245	$10,621
Depreciation	$144,902	$151,428	$6,526
Interest	$166,044	$172,492	$6,448
Taxes	-$63,196	-$16,006	$47,190
	$1,649,374	$1,720,159	$70,785
Non-LDC income (CDM, S/L)	$1,929	$433	-$1,496
Net Income	$76,824	$65,738	-$11,085

The increase in Net Income is attributable to a slight increase in distribution revenue.

<u>2018 vs 2019</u>

In 2019 we saw a significant drop in ROE from 4.12% to -9.46%.

Table Staff-2 – 2018 vs 2019 Factors Affecting Net Income

	2018	2019	2019 vs 2018
Revenue	$1,785,464	$1,833,470	$48,007
OM&A	$1,412,245	$1,672,123	$259,879
Depreciation	$151,428	$158,755	$7,327
Interest	$172,492	$262,401	$89,909
Taxes	-$16,006	-$2,025	$13,981
	$1,720,159	$2,091,254	$371,096
Non-LDC income (CDM, S/L)	$433	$24,377	$23,944
Net Income	$65,738	-$233,407	-$299,145

Net Income was down by $299,145 which was driven by the following major factors:

- O&M increased by $79,000 - $40,000 increase in line clearing and $46,000 increase in o/h lines expense
- Administration Expenses increased by $181,000. The major increases were bad debt expense $27,000, Admin labour and expense $35,000, Accounting and Audit fees due to the divestiture $97,000 and regulatory expenses (mandatory survey) $14,000.
- Interest Expense increase by $90,000 to facilitate the financing associated with North Bay's acquisition of ERHDC.

On October 1, 2019, North Bay Hydro Holdings Inc. acquired ERHDC and initiated the Cost of Service rate application review process to better address the variability in the returns.

Staff-3 – Responses to Letters of Comment

Question:

Following publication of the Notice of Application, the OEB received 2 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, 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:

A response has been provided to the matters raised in the 2 letters of comment and are attached as Appendix 1 – Letters of Comment Reply

The responses have been delivered to OEB Staff, since the contact information of the customers were redacted.

Staff-4 – Depreciation Expenses

Reference: Exhibit 2, pages 25-26

Preamble:

Excluding the costs of land, OEB staff notes that the depreciable costs of substation 4 decreased from $2,008,500 to $1,949,234 (forecast vs. actual). This is a decrease of 3%.

On page 26, Espanola Hydro shows that the depreciation expense of substation 4 decreased from $50,213 to $39,391 (forecast vs. actual). This is a decrease of 22%.

Question:

(a) Please explain why the depreciation expense decreased by 22% when the total cost of the depreciable assets only decreased by 3%.

(b) Please provide the calculations of the depreciation expense for substation 4.

Response:

(a) The depreciation expense decrease of 22% ($10,821) is due to i) the difference between the estimate in the ICM application and the final cost of the project and ii) incorrect depreciation rates being used in the original ICM application. The variance is calculated in the following Table Staff-4-1.

Table Staff-4-1 – ICM Variances

	Depreciation rate used in ICM	Depreciation rate used to record in Acct 1508	Depreciation rate variance	Cost used in ICM	Variance due to rate
Municipal Substation	2.50%	2.00%	-0.50%	$1,733,500	-$8,668
44 kV line Build	2.50%	2.16%	-0.34%	$275,000	-$943
				$2,008,500	-$9,611

	Cost used in ICM	Actual Cost	Cost Variance	Actual Depreciation rate	Variance due to Cost
Municipal Substation	$1,733,500	$1,690,036	-$43,464	2.00%	-$869
44 kV line Build	$275,000	$259,198	-$15,802	2.16%	-$341
	$2,008,500	$1,949,234	-$59,266		-$1,210
				Total Variance	-$10,821

b) Depreciation expense using the correct depreciation rates is shown in the following Table Staff-4-2:

Table Staff-4-2 – ICM Depreciation Expense

	Depreciation rate	Actual Cost	Calculated Depreciation	Depreciation Included in the Application	Variance
Municipal Substation	2.0%	$1,690,036	$33,801	$33,804	$3
44 kV line Build	2.5%	$259,198	$6,480	$5,592	-$888
			$40,281	$39,396	-$885

The $5,592 was being recorded to correct a previous over-depreciated amount.

Staff-5 – Depreciation Expenses

Reference 1: Chapter 2 Appendices, App.2-BA
Reference 2: Exhibit 2, Page 26

Preamble:
Espanola Hydro has rolled the substation 4 incremental capital module (ICM) into its fixed asset continuity schedule through adjustment entries made in the 2020 and 2021 continuity schedules under the "Adjustment Sub 4 ICM." OEB staff notes that the 2021 entry only includes the annual depreciation, which matches the $39,396 depreciation expense as noted on Page 26 of Exhibit 2 (it differs by $5, which is immaterial).

For the 2020 entries, OEB staff notes a total depreciation expense associated with the ICM to be $240,507. OEB staff understands this to be the accumulated depreciation associated with substation 4 from 2014 (when the ICM was approved) to 2020. This is a total of seven years. Since Espanola Hydro depreciates its asset on a straight-line basis, OEB staff expects the total accumulated depreciation recorded in 2020 to be $275,737 = (7 * $39,391).

Question:

(a) Please explain and show Espanola Hydro's calculations of the ICM's accumulated depreciation as recorded the 2020 continuity schedule. Please clarify the number of years' worth of depreciation this represents.

Response:
a) Included in the 2020 "Adjustment Sub 4 ICM" is, as noted above, $240,507 which represents the accumulated depreciation from 2014 to 2019 (6 years). The amounts were slightly varied each year due to error and therefore resulted in a variance. The seventh year is included in the Accumulated Depreciation "Additions" column. Included in the $37,374 in Account 1820 is $33,804 relating to the substation and included in the $57,690 in Account 1830 is $5,592 relating to poles, towers and fixtures for a total of $39,396 for the substation project brought into fixed assets.

Substation 4 - 2020 Continuity Schedule	
From Account 1508 - Depreciation 2014 to 2019	$240,507
2020 Depreciation - included in Account 1820	$33,804
2020 Depreciation - included in Account 1830	$5,592
	$279,903

Therefore the 2020 year end balances include 7 years of depreciation.

Staff-6 – ICM

Reference 1: Chapter 2 Appendices, Appendix 2-BA

Preamble:

In the above reference, OEB staff notes that Espanola Hydro has moved its substation 4 ICM assets into rate base by adding the gross book value and accumulated depreciation in the 2020 fixed asset continuity schedule. As per the Ontario Energy Board Accounting Procedures Handbook Guidance, March 2015, ICM assets are added to the applicable fixed asset account once approval to dispose the ICM deferral accounts and approval to include the ICM capital assets into rate base have been obtained.

Question:

a) Please confirm you agree with the statement above. If not confirmed, please explain.

b) Please revise the 2020 and 2021 fixed asset continuity schedules to add the appropriate gross book value and accumulated depreciation for the ICM assets in 2021 instead of 2020.

Response:

a) ERHDC has moved its substation 4 ICM assets into rate bases for representative purpose in the Chapter 2 filing requirements Appendix 2-BA. However, the actual entry will not be recorded until approval by the OEB and any resulting true up variances. The reason ERHDC included the ICM assets into rate base in 2020 is for capturing the proper amount of capital in rate base. The rate base is a calculation of average net fixed assets. If ERHDC showed the ICM assets in 2021 it would cut the average net fixed assets in half, thus reducing the amount included in rates over the next 5 years. Therefore, ERHDC believes it should leave substation 4 ICM asset adjustment in 2020.

b) Please see response above.

<u>Staff-7 – Cost of Power</u>

Reference: Chapter 2 Appendices, App.2-ZA and App.2-ZB

Preamble:

The following are the forecasted commodity prices Espanola Hydro has used in appendix 2-ZA:

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$20.09	$20.09
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$106.94	$106.94
Adjustments ($/MWh)				$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			$128.03

The forecasted supply costs have been updated by the OEB in its December 15, 2020 Letter Re: New Regulated Price Plan Prices Effective January 1, 2021. The HOEP $/MWh is now $20.87, GA $/MWh is now $83.62 and adjustments $/MWh is now $3.24.

Questions:

(a) Please update appendices 2-ZA, 2-ZB and Espanola Hydro's cost of power calculations.
(b) Please use the updated Ontario Electricity Rebate of 21.2% in appendix 2-ZB.
(c) Please update Espanola Hydro's working capital allowance calculations.

Response:

a) Chapter 2 Appendices have been updated to reflect the cost of power calculations effective January 1, 2021. The update can be viewed in the live Excel file named "ERHDC_2021_Filing_Requirements_Chapter2_Appendices_IRR_Response_20210325" which has been filed as part of ERHDC's IR Responses.

b) The Ontario Electricity Rebate of 21.2% has been updated in appendix 2-ZB and can be viewed in the live Excel file named "ERHDC_2021_Filing_Requirements_Chapter2_Appendices_IRR_Response_20210325" which has been filed as part of ERHDC's IR Responses.

c) The working capital allowance calculation has been updated and is reflected in the revised models submitted with ERHDC's IR Responses.

Staff-8 – Capital Expenditures

Reference: Exhibit 2, Page 35

Preamble:

Owing to its small size, Espanola Hydro noted that it is susceptible to material changes in its annual capital expenditures due to availability of employees (e.g. leaves of absence, retirements, etc.).

Question:

(a) Please list any material changes to historical capital expenditures as a result of a lack of available employees.
(b) What plans and steps has Espanola Hydro taken to minimize the impact of employee availability?
(c) Do Espanola Hydro's capital plans as presented in this application contain any contingency amounts to deal with risks associated with employee availability?

Response:

a) Although not recently, ERHDC has had long term absences for sickness (operations, mental health issues, replacing of retired employees, etc.). In these circumstances ERHDC would have attempted to engage outside contractors when possible. In so far that ERHDC was unable to engage outside contractors, it may have resulted in an impact to capital expenditures. ERHDC is unable to provide a specific list of any material changes to historical capital expenditures as a result of a lack of available employees.

b) To minimize the impact of employee availability, ERHDC has established a working relationship with a powerline construction contractor in the region to backfill should its own resources become unavailable.

c) ERHDC's capital plans as presented in this application consider the possibility of completing the work with a powerline construction contractor should its own employees become unavailable. The costs associated with the work completed by a contractor are expected to be nearly equal to the expenses that would be avoided due to a loss in its own labour force, so, no additional amounts have been carried.

Staff-9 – Capital Expenditures

Reference 1: Exhibit 2, Page 40
Reference 2: Chapter 2 Appendices, Appendix 2-AB

Preamble:

On page 40, Espanola Hydro noted that its average annual capital expenditures between 2016-2019 was $474,093. Espanola Hydro has not provided the capital expenditures for 2016 in Appendix 2-AB, but OEB staff has calculated it by multiplying $474,094 by four years and subtracting the capital expenditures in 2017-2019. By doing so, OEB staff calculates the 2016 capital expenditures to be $356,372.

Question:

(a) Please confirm if OEB staff's calculations are correct.
(b) If yes to a), please explain why the 2016 capital expenditures were significantly less than the rest of the historical years.

Response:

a) ERHDC's capital expenditures for 2016 is different than that calculated by OEB staff. The original calculation by ERHDC was erroneously based on a spreadsheet that had not been updated for 2016 actual costs.

Table Staff-9 below is the revised calculation of the average capital expenditures from 2016 to 2019, which now includes the capital expenditures for 2016.

Table Staff-9 – Revised Calculation of Average Capital Expenditures (2016-2019)

CATEGORY	2016	2017	2018	2019	Average
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	31	182	37	38	
System Renewal	347	467	393	338	
System Service	-	-	-	-	
General Plant	48	-	-	85	
TOTAL EXPENDITURE	426	649	430	461	492

b) As seen in part (a) above, the ERHDC's 2016 capital expenditures are in line with 2018 and 2019. The 2017 capital expenditures are higher due to outside costs related to Long Term Load transfers ($162,000) and the replacement of submarine cables ($62,000).

<u>Staff-10 – Capital Additions</u>

<u>Reference 1</u>: Chapter 2 Appendices, Appendices 2-AA, 2-BA

<u>Reference 3:</u> EB-2020-0249, Application, Page 10

<u>Preamble:</u>

OEB staff notes that Espanola Hydro filed its application on December 31, 2020.

<u>Question:</u>

(a) Please confirm if the capital additions for 2020 in Appendix 2-BA and capital expenditures for 2020 in Appendices 2-AA and 2-AB represent 2020 actual spending or was a forecast at the time of filing. If it is the latter, please update the evidence to reflect the most up-to-date values for 2020.

<u>Response:</u>

a) Appendices 2-AA, 2-AB and 2-BA have been updated to reflect 2020 actual spending. A copy of the updated Chapter 2 Appendices has been filed with ERHDC's IR Responses as an Excel file named:
"ERHDC_2021_Filing_Requirements_Chapter2_Appendices_IRR_Response_20210325"

Staff-11 – ICM

Reference 1: Exhibit 2, Page 44, Table 2-36

Preamble:

OEB staff notes that the ICM revenue requirement as shown in Table 2-36 for 2014 and 2021 don't reflect a full year's worth of revenue requirement. OEB staff assumes this is because the table reflects a pro-rated revenue requirement for the fiscal year (i.e. May-December for 2014 and January-April for 2021) to be able to be compared to the actual rate rider revenues. However, OEB staff notes that the 2014 and 2021 amounts added together is $138,072, which does not represent a full year's worth of revenue requirement (even though May-December plus January-April make a full year).

Question:

(a) Please explain how the ICM revenue requirement for 2014 and 2021 were calculated.

Response:

a) Table 2-36 has been updated to reflect the recalculated ICM Revenue Requirement. This has resulted in an under collection from customers of $35,917.

The original Table 2-36 is reproduced at Table Staff-11-1 below to show changes and the updated Table 2-23 is shown below as Table Staff-11-2.

Table Staff-11-1 – Original Table 2-36

	2014	2015	2016	2017	2018	2019	2020	2021	Total
Collection from Customers	$86,076	$159,676	$154,509	$152,004	$157,479	$157,397	$159,751	$53,250	$1,080,143
Recalculated ICM Revenue Requirement	$87,971	$158,976	$158,976	$158,976	$158,976	$158,976	$158,976	$50,101	$1,091,928
Over (Under) recovered	-$1,895	$700	-$4,467	-$6,972	-$1,497	-$1,579	$775	$3,149	-$11,785

Table Staff-11-2 – Updated Tale 2-36

	2014	2015	2016	2017	2018	2019	2020	2021	Total
Collection from Customers	$86,076	$159,676	$154,509	$152,004	$157,479	$157,397	$156,526	$53,250	$1,076,917
Recalculated ICM Revenue Requirement	$105,986	$158,976	$158,976	$158,976	$158,976	$158,976	$158,976	$52,993	$1,112,834
Over(Under) recovered	-$19,910	$700	-$4,467	-$6,972	-$1,497	-$1,579	-$2,450	$257	-$35,917

The previous version of the table used billing determinants from 2014 and 2021 to recalculate the ICM revenue requirement. However, we have now corrected this calculation which is reflected in the table above. Additionally, the 2021 collection from customers is based on using

2021 Load Forecast billing determinants in the projection of collection from customers. 2020 has been updated for actual collection from customers.

Staff-12 – SAIDI/SAIFI

Reference 1: DSP, Pages 21-23

Preamble:

Defective equipment is one of the largest contributors to Espanola Hydro’s outages

Questions:

(a) What asset classes are the largest contributors to outages?
(b) If available, please provide a table showing the number of historical customer interruptions per asset class and a table showing the number of historical customer hours of interruption per asset class. As well, please provide a table showing the SAIDI contribution per asset class and a table showing the SAIFI contribution per asset class.

Response:

(a) As can be seen in row four in the table below in response to 2-Staff-12 (b), the largest contributor to outage duration over the period 2015-2019 is underground primary cable. The resulting SAIDI value of 0.2152 is due to a single cable failure in 2016 that affected 288 customers for a duration of 2.5 hours. Referring to row 5 of the same table, the largest contributor to outage frequency is insulators. The resulting SAIFI value of 0.7757 is attributable to a single 44kV station insulator failure also in 2016 that affected 2593 customers for a duration of just over one minute.

(b) Below is a table summarizing the number of historical customer interruptions per asset class along with SAIDI and SAIFI. It should be noted that of a total of all equipment failures reported below, the two failures referenced in part (a) above (U/G cable and station insulator) were overall by far the primary contributors to SAIDI and SAIFI for the period.

Table 1-Staff-12 – Historical Outage Statistics by Asset Class for 2015-2019

Asset Class	Customers Interrupted	*Total Customer Hours of Interuption*	*SAIDI*	*SAIFI*
Transformers	36	122.5	0.037164	0.010912
Services (wires, connectors)	117	124.25	0.037493	0.035295
Switches	32	79.75	0.023983	0.009638
U/G Primary Cable	288	720	*0.2152*	*0.0861*
Insulators	2593	43.2	*0.0129*	*0.7757*

Staff-13 – Cost Performance

Reference 1: DSP, Page 25

Preamble:

Espanola Hydro noted that its 2019 cost performance per customer was $758 / customer and was an 11% increase over 2018 due to higher administrative costs from the sale of Espanola Hydro to North Bay Hydro.

Espanola Hydro further noted that its projected 2020 cost per customer is $761, a modest 0.37% increase over 2019.

Question:

(a) Given that the sale and associated costs of the sale of Espanola Hydro was a one-time event that occurred in 2019, please explain why there is not a corresponding decrease in Espanola Hydro's projected cost performance in 2020.

Response:

a) The cost performance per customer referenced above are from the benchmarking spreadsheet from Pacific Economics Group Research (PEG). The cost per customer consists of OM&A costs and capital costs which are adjusted by various factors in the PEG model.

ERHDC's OM&A expenses are approximately $100,000 (5%) lower in 2020 than 2019, however capital expenditures in the model were estimated to be $260,000 higher in 2020 compared to 2019. The increase in capital expenditures offset the decrease in OM&A expenses.

ERHDC has updated 2020 in the PEG model with the current data which includes a reduction in capital over the original estimate for 2020. The revised cost per customer for 2020 is $739 per customer.

Staff-14 – O&M Costs

Reference 1: DSP, Page 28, Table 2-12

Preamble:

As shown in table 2-12, Espanola Hydro's O&M cost per customer and per line have increased by an average of 7% annually. OEB staff notes that this is significantly above inflation.

Table 2-12: Average Percent Change for Cost Metrics

Metric	2015	2016	2017	2018	2019	Average % Change	ERH Target
Cost Per Customer	--	2%	-1%	3%	11%	4%	Group 2 (between 10% and 25% below predicted costs)
Total Cost per Kilometer of Line	--	2%	-2%	4%	11%	4%	
O&M Cost per Customer	--	17%	-10%	9%	12%	7%	
O&M Cost per Kilometer of Line	--	17%	-10%	9%	12%	7%	
O&M Cost per Average Peak Capacity	--	20%	-4%	-13%	11%	3%	

Question:

(a) Given the limited growth of Espanola Hydro's distribution system, please explain the large increases in system O&M.

Response:

Please refer to the chart below for an explanation of O&M from 2015 to 2019.

Table Staff-14 – Explanation of O&M from 2015 to 2019

2015 O&M	$553,731
2019 O&M	$719,932
Increase	$166,201
Average annual increase	7.50%

Increase 2015 to 2019		$166,200
The increase in costs from 2015 to 2019 include:		
Increase due to allocation of PUC Contract between O&M and Admin (1)	$26,000	
Increase in Line clearing (2)	$29,000	
Increase in o/h lines material costs	$30,600	
Increase in misc. distribution expense - engineering fees	$5,800	
Increase in poles material	$11,000	
Sub 4 materials	$10,500	$112,900
Remaining increase		$53,300
Average annual increase remaining		2.41%

(1) service contract allocation increased to O&M and decreased to Admin. - total contract cost increased by 2.0 to 2.75% per year
(2) - due to availability of line clearing contractor, line clearing costs varied over the years

Staff-15 – System Losses

Reference 1: DSP, Page 31

Preamble:

Espanola Hydro had system losses of 6% in 2017 and averaged 4.2% over 2015-2019

Question:

(a) What is the reason for the large amount of system loss in 2017?
(b) What steps has Espanola Hydro taken since its last cost of service application to reduce its system losses?

Response:

a) ERHDC has extensively investigated the reason for the system losses in 2017. A review has been done of the metered consumption, a reconciliation of hydro one invoices, and the amount of embedded generation. However, ERHDC is not able to determine the cause of large system losses in 2017.

b) In an effort to reduce system losses, ERHDC always looks for opportunities when doing renewal projects. In the past several years, this has included using larger diameter conductor for express feeders where existing 1/0 conductor was replaced with 336mcm conductor and ensuring that three phase loads are balanced during rebuild work.

Staff-16 – System Renewal

Reference 1: DSP, Page 40

Preamble:

Espanola Hydro noted that the health index of its MS1 is very poor and along with MS2 and MS3 need to be renewed/replaced within the next ten years.

Questions:

(a) Does Espanola Hydro have plans for replacing these substations already? If so, when does Espanola Hydro expect to replace these substations?
(b) What are Espanola Hydro's contingency plans in an N-1 event where one substation is taken out of service?

Response:

(a) No; Although there is a growing need to address MS1, 2 and 3, ERHDC does not have an immediate replacement plan. Due to the relatively large investment and the long timelines associated with a station rebuild, and because ERHDC has filed a one-year capital plan only, it has considered it reasonable to defer its decision on such an investment until a more extensive distribution planning exercise can be completed.

(b) ERHDC completed the addition of a new fourth municipal station MS-4 and upgrades of several main interconnecting feeders in the town of Espanola within the past five years. With this new MS, and the associated new feeders, there is adequate capacity and switching flexibility to support the full load of the town in an N-1 contingency event.

Staff-17 – System Renewal

Reference 1: DSP, Page 54

Reference 2: Chapter 2 Appendices, Appendix 2-AA

Preamble:

Espanola Hydro employs a run-to-failure strategy for its distribution transformers and has an annual budget to replace these transformers. OEB staff notes that the "OH Transformer Renewal" program has a budget in 2021 that is significantly higher than the historical years.

Question:

(a) Please explain the reason for the larger budget for transformer replacement program. Does Espanola Hydro expect to experience more overhead transformer failures than it has historically?

Response:

(a) The transformer budget proposed in this application is larger than historically proposed budgets for two reasons. Firstly, a number of transformers are to be ordered in response to a shrinking inventory that requires replenishment. This will provide adequate levels to maintain response levels to customer demand and emergency replacements. Secondly, in response to regulatory requirements, ERHDC is in the process of testing its poletop transformers for PCB contamination. Testing in the Massey and Webbwood areas are complete and testing in the town-proper of Espanola are planned for this year. The budget proposed reflects a need to replace a number of these transformers which are expected to exceed acceptable PCB contamination levels.

Staff-18 – System Renewal

Reference 1: DSP, Page 65

Preamble:

As noted by Espanola Hydro, limited or no investments into system renewal generally increase system O&M as remaining assets continue to age and increase the probability of failure.

Question:

(a) Has Espanola Hydro done any analysis on the impact of system renewal spending on system O&M? Has Espanola Hydro considered increasing system renewal spending to help offset and reduce system O&M? If yes, please provide the analysis; if no, why not?

Response:

(a) No, ERHDC has not done an analysis on the impact of system renewal spending on system O&M. Such an analysis would necessitate a considerable expenditure to hire external subject matter experts that greatly exceed ERHDC's ability to afford. If the OEB believes that this information would be useful across the sector, ERHDC would welcome OEB expert guidance in this area. In the interim, ERHDC has filed a simplified one-year capital plan as part of this application pursuant to OEB approval in letter dated September 8, 2020. It would not be reasonable to consider trade-offs between system renewal spending and system O&M in such a simplified one-year plan. The trade-off horizon is more likely to be 10 to 20 years or more, if such a realistic trade-off could even exist.

Staff-19 – Customer Service

Reference 1: DSP, Page 15

Reference 2: Exhibit 4, Page 6

Preamble:

Espanola Hydro's Customer Care Department fields calls from customers. As indicated in the DSP, staff turnover resulted in longer average talk times and therefore decreased the number of calls answered on time.

In Exhibit 4, Espanola Hydro noted that it has a services agreement with PUC Services Inc. One of the functions contracted out to PUC Services Inc. is customer service.

Questions:

(a) Please explain if the "Customer Care Department" refers to employees of PUC Services Inc. that are contracted for Espanola Hydro's customer service.
  i. If yes, what assurances does Espanola Hydro have from PUC Services Inc. that Espanola Hydro's customer service quality would not be impacted by future potential staff turnover at PUC Services Inc.?
  ii. If no, please explain why answering calls is not a function covered under the services agreement with PUC Services Inc. How many current Espanola Hydro employees work as customer service representatives? Is there any overlap between Espanola Hydro's Customer Care Department and the services it receives from PUC Services Inc.?

Response:

a) ERHDC's Customer Care Department refers to the services provided by PUC Services Inc. ("PUC Services") under long term contract.
  i. The contracted service level standard applicable to these services is described in the contract to require a service level "not less favourable" than any other of PUC Services customers/clients. Service levels have consistently met requirements and ERHDC has not had cause for concern. With the development of the OEB Scorecard framework several years ago, specific metrics available have exceeded the Industry Target levels with the one

exception of 2019 telephone call answers dipping below the 65% target to 63.04%. In 2020 service levels returned to being above the Industry Target level even with the challenges experienced during the COVID-19 pandemic and we are confident the service level provided will continue to meet expectations.

ii. N/A.

Staff-20 – Connection Forecast

Reference 1: Exhibit 3, Page 5

Reference 2: Tariff of Rates and Changes

Preamble:

Espanola Hydro stated that "For the 2020 Bridge Year and 2021 Test Year Street Lights have been updated from number of devices to number of connections." The tariff of rates and charges identifies that the charge is per connection.

Question:

(a) Does Espanola Hydro propose to charge customers on a per connection or a per device basis?

Response:

a) ERHDC is proposing to charge customers on a per connection basis.

Staff-21 – Energy Forecast

Reference 1: Exhibit 3, Pages 9 - 11

Reference 2: Load Forecast Model, Act vs Pred Chart

Preamble:

Espanola Hydro has used explanatory variables for heating, cooling, the number of days in the month, and an indicator of the spring and fall months. No variables have been included related to CDM, a trend, or any indicator of economic activity. Over that time, Actual energy use reduced from 64.8 GWh in 2010 to 62.1 GWh in 2019.

Espanola Hydro explained that an adjustment has been made for changes in street lighting consumption in 2014 and 2020. This reflects a reduction from 617,088 kWh in 2013 to 368,606 kWh in 2014, and a further reduction to 224,919 kWh in 2020.

The Actual vs Predicted chart indicates that Actual consumption was higher than predicted in every year from 2010 to 2014, and less than actual in every year from 2015 to 2019.

Questions:

(a) Have any explanatory variables that exhibit a trend such as CDM, an indicator of economic activity, or a trend variable been attempted, if so, what were the results?
(b) Has a dummy variable been attempted to test for the reduction in street lights in 2014, and if so, what was the result?
(c) As a scenario, please provide a regression model and resulting forecast with a trend variable indicating 1 in January 2010, increasing by 1 each month, and reaching 120 in December 2019.

Response:

a) There were no other explanatory variables such as CDM, economic activity indicators or trend variables attempted.

b) A dummy variable was not attempted to test for the reduction in street lights in 2014.

c) A regression model with a trend variable results are shown in Table Staff-21 below:

Table Staff-21 – Regression Model with a Trend Variable

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	97%							
R Square	93%							
Adjusted R Square	93%							
Standard Error	304991.2103							
Observations	120							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	5	1.47896E+14	2.95793E+13	317.9894277	3.3929E-65			
Residual	114	1.06042E+13	93019638367					
Total	119	1.58501E+14						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1,221,482	1,068,277	1.143412428	0.255262822	-894767.5425	3337730.573	-894767.5425	3337730.573
Heating Degree Days	3,515	120	29.30618147	6.66818E-55	3277.511451	3752.73048	3277.511451	3752.73048
Cooling Degree Days	6,851	1,838	3.726597553	0.000303639	3209.073315	10492.67824	3209.073315	10492.67824
Spring Fall Flag	(420,820)	67,189	-6.263264833	6.87619E-09	-553920.1404	-287719.9202	-553920.1404	-287719.9202
Number of Days in Month	96,020	35,339	2.717116809	0.007612797	26013.92678	166026.6224	26013.92678	166026.6224
Trend Variable	(4,473)	807	-5.542406771	1.9494E-07	-6071.438768	-2874.087856	-6071.438768	-2874.087856

Overall using trend variable represent a better regression model with the values for Multiple R, R Square and Adjusted R square all being higher than the original Load Forecast model presented with the application. The trend variable is indicating that as time passes we are seeing an overall declining trend in consumption of 4,473 kWh. When comparing this logic to historical purchases it matches the overall trend we have seen in ERHDC for the last 10 years.

Staff-22 – Other Revenues

Reference 1: Exhibit 3, Page 27

Reference 2: Chapter 2 Appendices, Appendix 2-JC

Reference 3: Exhibit 4, Appendix 4-A, Page 11, Schedule A

Preamble:

Espanola Hydro noted that it no longer performs water billing collections for the Town of Espanola.

Question:

(a) When did Espanola Hydro stop performing this service?
(b) OEB staff notes account 5315 – Customer Billing in Appendix 2-JC. Were the costs associated with performing this service recorded in this account? If yes, was there a decrease in the annual costs recorded in this account due to no longer having to perform the service? If not, in which account were the costs associated with performing this service recorded?

One of PUC Services Inc.'s responsibilities as listed in the service agreement in reference 3 is for water billing/collection services.

(c) Has the cost of the service agreement with PUC Services Inc. decreased to reflect the fact water billing/collection is no longer required?

Response:

a) Espanola Hydro stopped performing water billing for the Town of Espanola following the period ending September 30, 2019. The last bills were issued October 19, 2019 and reconciliation of all accounts was completed by year end.

b) The costs associated with performing the billing service were recorded in account 5315. There was no change in the cost recorded in this account for the PUC Services contract. The small amount of internal labour that was associated with this function would no longer be in this account.

c) There was no decrease in service agreement costs from PUC Services as there was no difference in costs for bill processing, mailing, etc. due to discontinuation of the water billing.

Staff-23 – Operating Expenses

Reference 1: Exhibit 4, Page 7

Reference 2: BDR Report, Page 9, Table 2

Preamble:

Espanola Hydro noted that, although its billing and collection costs of $121 per customer are high compared to other utilities, there are differences in how Espanola Hydro and other utilities categorize and record expenses, and that Espanola Hydro's total administrative costs per customer are reasonable.

Questions:

(a) Please detail how Espanola Hydro differs from other utilities in recording its billing and collection expenses.

The BDR Report has a similar table comparing Espanola Hydro's costs to other utilities, albeit using 2007 data.

(b) OEB staff notes that, based on the 2007 data, Espanola Hydro's billing and collection costs per customer is $75 and is close to the average of the comparator utilities in the table. Please explain the reason why Espanola Hydro's costs have increased from $75 / customer (middle of the benchmarking group) to $121 / customer (high end of the benchmarking group).

(c) Is this increase due to a change in the way Espanola Hydro records its billing and collection expenses or is it because of an increase in costs? If the former, please explain the changes. If the latter, please explain the reason for the increase given that Espanola Hydro's customer base has not materially increased.

Response:

a) ERHDC has a services agreement with PUC Services. The agreement includes services such as customer invoice preparation and mailing, scheduling and arranging meter reads, processing of payments, collections, customer service, participation in Board meetings, supervision of all staff, oversight/awareness/monitoring of daily operations, regulatory & legislative requirements, purchasing, human resources, CDM, Engineering services, etc. and the preparation of annual budgets. ERHDC receives a monthly invoice from PUC Services.

The monthly invoice amount is allocated to the variance general ledger accounts based on a fixed percentage. Please refer to Staff-28 for a breakdown of costs for the services agreement.

b) Over the years the percentage allocations to the various general ledger accounts have been modified for such events as the combining of the management and billing/customer service contracts and the change from PUC Services providing the Lines Supervisor to ERHDC hiring the Lines Supervisor. In addition, charges for services provided beyond the monthly contract amount vary from year to year. Please refer to Staff-28 for a breakdown of costs for the services agreement.

Including inflationary increases and changes in regulatory requirements since 2007 ERHDC's billing and administrative cost per customer has increased by 2.60% as indicated below in Table Staff-23-1:

Table Staff-23-1 – Billing and Administrative Cost Per Customer (2007 and 2018)

	Billing/Coll Expense per Customer	Admin & Comm Rel per customer	Bill/Coll/Admin/ Comm Rel per Customer
2007	$75.00	$89.00	$164.00
2018	$120.86	$96.56	$217.42
Increase	$45.86	$7.56	$53.42
Percentage Increase	61.15%	8.49%	32.57%
Annualized Increase 2007 to 2018 (11yrs)	4.43%	0.74%	2.60%

ERHDC's total billing and administrative expenses are in the lower end of the benchmarking group and are 19% below the average as indicated below in Table Staff-23-2:

Table Staff-23-2 – 2018 Costs per Customer in Comparison to LDCs with Fewer than 6,000 Customers

LDC	Billing/Coll Expense per Cust	Admin & Comm Rel per Cust	Bill/Coll/Admin/ Comm Rel per Cust
Hydro Hawkesbury Inc.	$72.34	$85.04	$157.39
Northern Ontario Wires Inc.	$114.81	$84.77	$199.58
Espanola Regional Hydro Distribution Corporation	$120.86	$96.56	$217.42
Renfrew Hydro Inc.	$96.13	$121.75	$217.89
Hearst Power Distribution Company Limited	$106.01	$124.10	$230.11
Rideau St. Lawrence Distribution Inc.	$84.63	$149.98	$234.61
Cooperative Hydro Embrun Inc.	$83.21	$170.56	$253.77
Sioux Lookout Hydro Inc.	$114.01	$142.37	$256.38
Fort Frances Power Corporation	$76.11	$185.24	$261.34
Wellington North Power Inc.	$89.28	$177.28	$266.55
Kenora Hydro Electric Corporation Ltd.	$95.85	$185.68	$281.54
West Coast Huron Energy Inc.	$109.93	$197.27	$307.20
Hydro 2000	$123.12	$187.97	$311.09
Atikokan Hydro	$106.02	$244.81	$350.83
Chapleau Hydro	$93.71	$374.58	$468.29
		Average	$267.60
		ERHDC compared to average	-19%

c) Please refer to Staff-28 for a breakdown of costs for the services agreement.

Staff-24 – Regulatory Costs

Reference 1: Chapter 2 Appendices, Appendix 2-M

Reference 2: Exhibit 4, Page 41, Table 4-31

Table 4 - 31 Regulatory Costs

Service	$	Expense Included in Test Year
Legal and rates consulting expenses to complete the application	$100,000	$20,000
Consultant - completion of application, interrogatories, settlement conference, draft settlement and final order	$282,539	$56,508
Services related to the Distribution System Plan and Asset Management Plan	$65,000	$13,000
Legal and rates consulting expenses for the settlement conference	$50,000	$10,000
Intervenor expenses	$50,000	$10,000
OEB Costs	$20,000	$4,000
Settlement conference expenses	$5,000	$1,000
LRAM consulting services	$10,000	$2,000
	$582,539	$116,508

Reference 3: Exhibit 2, Page 31

Preamble:

In Appendix 2-M, under "Regulatory Costs (One-Time)", the description for item 8 is incorrect.

Questions:

(a) Please confirm if item 8 with a cost of $65,000 refers to costs related to the DSP and Asset Management Plan.
(b) OEB staff notes that Espanola Hydro has deferred the preparation of a formal Asset Management Plan until after its merger with North Bay Hydro and the current plan is simply a continuation of the status quo. Please explain what costs are associated with the Asset Management Plan if it has been deferred and Espanola Hydro is simply maintaining the status quo.
(c) For Espanola Hydro's legal and consulting costs, please provide the actual costs incurred to date.
(d) For the consultant costs, which consultants are these costs associated with?

Response:

a) ERHDC confirms that the $65,000 refers to costs related to the DSP and AMP.

b) As part of this Cost of Service application, ERHDC proposed, and the OEB approved, scaling back the scope of the DSP as follows:

i) Deferring completing the formal Asset Management Plan and Asset Condition Assessment until after the North Bay Hydro merger.

ii) Limiting the DSP to a limited one (1) year forward test year plan. The goal would be to set out the plan for the 1 year until merger with North Bay Hydro is completed.

Although the scope of the DSP was scaled back, a DSP was still required and was completed at a reduced cost over the cost of a full DSP. The completed DSP is in Exhibit 2, Appendix 2-B.

c) The legal costs incurred to date are $104,215 and the consultant costs are $353,991

d) The consultants consist of Metsco, Indeco and PUC Services.

Staff-25 - Employees

Reference 1: Exhibit 4, Pages 15, 26

Preamble:

Espanola Hydro has 1.25 FTEs embedded in rate base for the administrative / financial / regulatory functions.

Questions:

(a) Please confirm that, when Espanola Hydro says that the office assistant resource increased to full time, this means that Espanola Hydro is increasing its FTE for these functions from 1.25 to 2 in the test year.

(b) The costs being recorded in account 5615 for these FTEs have increased from $0 in the 2012 test year to $58,398 in the 2021 test year. If there are 1.25 existing FTEs embedded in base rates, please explain why the 2012 amount is $0. Does the $58,398 amount correspond to the costs of both FTEs?

Response:

a) The increase to the office assistant resource to full time in not occurring in the 2021 Test Year. The increase to full time was phased in between the 2012 Approved and 2016. As a result, the FTE count in the historical years 2017 to 2019 and in the Bridge and Test Years include the full time FTE.

b) The 1.25 FTEs were allocated to accounts 5315, 5320 and 5610 in the 2012 Test year budget. In the 2021 Test Year the 2.0 FTEs have been allocated to accounts 5315, 5320, 5610 and 5615. The $58,398 is the allocation of the Admin Assistant and the Manager of Accounting and is allocated to accounts 5315, 5320 and 5610.

Staff-26 – OM&A

Reference 1: Exhibit 4, Page 19 (Appendix 2-JB)

Reference 2: Exhibit 4, Page 26 (Appendix 2-JC)

Preamble:

For line clearing account 5135, Appendix 2-JB shows a net increase of $28,639 (-$14,201 + $63,850 - $21,010) from the 2012 test year to the 2021 test year. For the same account, Appendix 2-JC shows a net decrease of $101,051 from the 2012 test year to the 2021 test year.

Questions:

(a) Please reconcile the two tables. Have line clearing costs increased or decreased?

Response:

a) The net increase as shown in Appendix 2-JB of $28,639 (-$14,201 + $63,850 - $21,010) is from 2016 to the 2021 test tear.

The total decrease of $101,051 as shown in 2-JC is from the 2012 test year to the 2021 test year.

Line clearing costs have decreased from the 2012 test year to the 2021 test year.

Staff-27 – Purchasing Policies

Reference: Exhibit 4, Pages 38-39

Preamble:

Espanola Hydro's purchasing policies require authorization from the Chief Financial Officer for purchases above certain amounts.

Questions:

(a) Given that Espanola Hydro no longer has a Chief Financial Officer, who now grants authorization?
(b) For amounts that require the president or treasurer – are these management roles currently filled by PUC Services Inc.?
(c) Who reviews and grants authorization for the costs associated with PUC Services Inc. service agreement? Does PUC Services Inc. authorize these costs as management for Espanola Hydro?

Response:

a) The previous policy remains in place, with the exception that the Manager of Accounting replaces the Chief Financial Officer.

b) No. These roles are currently filled by the Board of ERHDC.

c) Contract costs of management and customer services provided by PUC Services as detailed under the services agreement are approved by the ERHDC. PUC Services does not authorize these costs as management for ERHDC.

Staff-28 – Third Party Contracts

Reference 1: Exhibit 4, Pages 39

Reference 2: Exhibit 4, Appendix 4-A, Schedule B

Questions:

(a) Please provide a breakdown of the costs for the services agreement with PUC Services Inc. as noted in Table 4-29.
(b) Please reconcile the costs with the fee schedule as detailed in the service agreement with PUC Services Inc. in Appendix 4-A, Schedule 'B' – Fees.
(c) OEB staff notes that the year-over-year increases for the service agreement exceed inflation (10% increase in 2018 and 6% increase in 2019). Please explain the reason for the increases in costs for the service agreement.
(d) What are the 2021 costs for the service agreement that Espanola Hydro has included in its 2021 OM&A budget?

Response:

a) The cost breakdown for the services agreement with PUC Services is provided in Table Staff-28-1 below.

Table Staff 28-1 – Costs Breakdown for PUC Services Agreement

	2017	2018	2019
Table 4-29 Vendor Purchases	$414,821.88	$456,943.86	$485,205.60

Account charged	Account Description	2017	2018	2019
1835.1.02.00	O/H Conductors/ Devices Material	$541.63		
4380.5.01.00	CDM Expenses		$49,747.88	$56,475.96
4380.6.01.00	AFT Expenses		$44,000.00	$22,000.00
5005.1.00.00	PUC Supervision	$63,315.35	$55,678.99	$62,381.28
5025.1.00.00	OH Lines - Expenses			$5,455.40
5045.1.00.00	UG Lines Expense	$1,071.91		
5105.1.00.00	Maintenance - PUC Supervision	$60,660.94	$52,698.16	$59,062.07
5315.1.05.02	Billing - Postage	$3,117.52		
5315.1.06.00	Contract SSMPUC 70%	$114,859.77	$102,639.40	$114,554.61
5315.1.07.05	Retailer Settlement PUC	$42,508.13	$38,010.86	$42,423.52
5315.1.08.05	STR - Other Assoc. Costs	$2,242.46	$1,897.50	$2,070.00
5320.1.05.02	Billing Software Maint.	$10,752.55	$7,159.19	$7,971.83
5320.1.06.00	Contract SSMPUC 30%	$49,544.05	$44,088.63	$49,206.77
5320.1.07.05	Retail Settlement PUC	$18,428.35	$16,514.71	$18,431.84
5620.1.07.00	NETWORK ADMINISTRATION			$164.50
5630.1.06.00	PUC Supervision	$47,779.22	$44,508.54	$44,516.52
7777.1.03.00	#3 Truck			$491.30
		$414,821.88	$456,943.86	$485,205.60

b) Please see Table Staff-28-2 below for reconciliation of costs with the fee schedule as detailed in the service agreement with PUC Services.

Table Staff-28-2 Reconciliation of Costs with Fee Schedule

Service Contract Fees per Contract	1-Jun-16	1-Jun-17	1-Jun-18	1-Jun-19
Management Services	$156,141.32	$160,044.86	$164,045.98	$167,326.90
Customer Services	$5.26	$5.39	$5.53	$5.64
# of Customers	3,327	3,327	3,346	3,346
IT Server Hosting Services	$7,500.00	$7,687.50	$7,879.69	$8,037.28
EBT Hub Services (pass-through)	$172.50	$172.50	$172.50	$172.50
Monthly Service Fees calculated from annual fees above	Jan. 1, 2017 to May 31, 2017	June 1, 2017 to May 31, 2018	June 1, 2018 to May 31, 2019	June 2019 to Dec. 31, 2019
Management Services	$13,011.78	$13,337.07	$13,670.50	$13,943.91
Customer Services	$17,500.02	$17,932.53	$18,503.38	$18,871.44
IT Server Hosting Services	$625.00	$640.63	$656.64	$669.77
EBT Hub Services (pass-through)	$172.50	$172.50	$172.50	$172.50
	$31,309.30	$32,082.73	$33,003.02	$33,657.62

Annual Fees calculated from monthly fees above		2017	2018	2019
Jan to May (5 months)		$156,546.48	$160,413.63	$165,015.10
June to Dec (7 months)		$224,579.09	$231,021.13	$235,603.35
		$381,125.57	$391,434.77	$400,618.45
Annual Contract Fees per above		$381,125.61	$391,434.79	$400,618.45
Additional Services		$1,613.54	$3,843.91	$6,111.20
Additional Services - CDM Progam			$49,747.88	$56,475.96
Additional Services - AFT			$44,000.00	$22,000.00
Total Monthly Contract Costs plus Add'l Services		$382,739.15	$489,026.58	$485,205.61
Balance per G/L		$414,821.88	$456,943.86	$485,205.60
Difference - Jan 2018 expense recorded in Dec of 2017 (net balance of zero between 2017 and 2018)		$32,082.73	-$32,082.72	-$0.01

c) The monthly service agreement increases for 2018 and 2019 were in accordance with the service agreement (2.5% and 2.0%). The increase in costs over the service agreement were the result of additional services provided, the majority of which were to administer the CDM and AFT programs.

d) The 2021 costs for the service agreement that ERHDC has included in its 2021 OM&A budget is presented below in Table Staff-28-3.

Table Staff-28-3 – 2021 Costs for Services Agreement included in 2021 OM&A

Account charged	Account Description	2021 $
5005.1.00.00	PUC Supervision	$65,291
5105.1.00.00	Maintenance - PUC Supervision	$61,855
5315.1.06.00	Contract SSMPUC 70%	$110,952
5315.1.07.05	Retailer Settlement PUC	$41,607
5315.1.08.05	STR - Other Assoc. Costs	$2,133
5320.1.05.02	Billing Software Maint.	$17,185
5320.1.06.00	Contract SSMPUC 30%	$46,230
5320.1.07.05	Retail Settlement PUC	$16,180
5630.1.06.00	PUC Supervision	$44,673
		$406,104.30

Staff-29 – Capitalization Policies

Reference 1: Exhibit 4, Page 43

Reference 2: Exhibit 1, Page 21

Preamble:

Espanola Hydro stated that it does not apply the half-year rule; instead, Espanola Hydro records a full year's worth of depreciation in the year of acquisition.

In Exhibit 1, Espanola Hydro noted that one of the differences between its capitalization policy and North Bay Hydro Distribution Limited's capitalization policy is that North Bay Hydro Distribution Limited does apply the half year rule – the impact to Espanola Hydro's rates is immaterial.

Questions:

(a) Given that Espanola Hydro expects to adopt North Bay Hydro Distribution Limited's capitalization policy in the anticipated future merger in 2022, has Espanola Hydro considered adopting the half-year rule starting in this cost of service so to conform to North Bay Hydro Distribution Limited's capitalization policy?

Response:

a) ERHDC did consider adopting the half year rule starting in this cost of service application. However given that ERHDC's capital additions are on average $500,000 per year this would result in an immaterial effect on the overall revenue requirement of this application. Therefore, ERHDC decided to wait to undergo this change.

As explained in Exhibit 1 and Table 1-9[1] ERHDC is able to confirm that accounting policies are appropriate, align with NBHDL's accounting policies and there are no material differences.

[1] EB-2020-0020 – Exhibit 1 dated December 31, 2020, pages 21 and 22.

Staff-30 – LRAMVA Recovery Period

Reference 1: Exhibit 4, Pages 77-79

Reference 2: Appendix 4-K

Preamble:

Espanola Hydro has requested to recover its LRAMVA balance over five years.

Question:

(a) Please provide a table that shows the rate impacts of recovering the LRAMVA balance over 1, 2, 3, and 4-year periods.
(b) Please discuss if Espanola Hydro has had any discussion with the Municipality of Espanola related to the recovery of its street lighting LRAMVA balance. As part of your response, please indicate if the Municipality would be amenable to a shorter recovery period.

Response:

a) The Table Staff-30 below shows the rate impacts of recovering the LRAMVA balance over 1,2,3 and 4-year periods.

Table Staff-30 - Bill Impacts

			Original Proposal - 5 Year LRAMVA		4 Year LRAMVA		3 Year LRAMVA		2 Year LRAMVA		1 Year LRAMVA	
Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/ Decrease	Total Bill Impact %	Total Bill Increase/ Decrease	Total Bill Impact %	Total Bill Increase/ Decrease	Total Bill Impact %	Total Bill Increase/ Decrease	Total Bill Impact %	Total Bill Increase/ Decrease	Total Bill Impact %
Residential	750	0	$8.73	7.25%	$ 8.79	7.30%	$ 8.97	7.45%	$ 9.27	7.70%	$ 10.17	8.45%
Residential	318	0	$6.29	10.74%	$ 6.32	10.79%	$ 6.39	10.92%	$ 6.52	11.14%	$ 6.90	11.79%
Residential	848	0	$9.29	6.91%	$ 9.36	6.96%	$ 9.56	7.11%	$ 9.90	7.36%	$ 10.91	8.12%
GS<50	2,386	0	$22.80	6.16%	$ 23.57	6.37%	$ 24.71	6.68%	$ 27.18	7.34%	$ 34.42	9.30%
GS>50	44,361	115	$538.50	5.98%	$ 546.61	6.07%	$ 560.11	6.22%	$ 587.11	6.52%	$ 668.11	7.42%
USL	456	0	$4.14	5.50%	$ 4.10	5.45%	$ 4.00	5.30%	$ 3.85	5.11%	$ 3.30	4.39%
Sentinel Light	81	0.22	$2.37	15.22%	$ 2.35	15.06%	$ 2.31	14.81%	$ 2.23	14.30%	$ 2.31	14.81%
Street Light	14238	41.8	-$67.37	-1.65%	$ 204.29	5.02%	$ 657.06	16.14%	$ 1,562.59	38.37%	$ 4,279.19	105.09%

Based on the table above we see that collecting the LRAMVA rate rider from the Street Light class over 3 years or less increases the overall bill impacts over 10%. A 4 year rate rider results in a 5.02% total bill impact and a 5 years results in a -1.65% total bill impact.

b) In response to Chapter 2 Filing Requirements, Exhibit 7 – Cost Allocation, Section 2.7.1.1 Specific Customer Class(es)[2], ERHDC has sent a letter to Street Light customers regarding the updated change in methodology for the calculation in their bill and overall they will see a slight reduction in their monthly bill.

ERHDC has not discussed the recovery of its street lighting LRAMVA balance with the Municipality of Espanola as ERHDC did not interpret this as part of the Chapter 2 Filing Requirements. A shorter recovery period has not been discussed with the Municipality.

[2] Ontario Energy Board Filing Requirements For Electricity Distribution Rate Applications - 2020 Edition for 2021 Rate Applications - Chapter 2 Cost of Service, page 50.

Staff-31 – Promissory Note

Reference: Exhibit 5, Page 5

Preamble:

Espanola Hydro stated that it expects to finalize in 2021 a promissory note with North Bay Hydro Distribution Limited for $230,000.

Question:

(a) Has Espanola Hydro finalized the terms of this promissory note? If yes, please provide a copy of the promissory note.

Response:

a) ERHDC has not finalized the terms of the promissory note but will provide a copy of the promissory note as soon as it is available.

Staff-32 – Weighting Factors

Reference 1: Exhibit 7, Page 2

Preamble:

The services weighting factors for all rate classes except residential are less than 1.0. Espanola Hydro indicates that it relied on costs of labour, materials, outside costs, as well as discussions with staff in the development of weighting factors.

The weighting factor for meter reading is 1.0 for all metered rate classes.

Question:

a) Please provide the derivation of the services weighting factors. In doing so, please detail which costs are paid by Espanola Hydro, and explain when a customer would be responsible for some or all of their service connection.

b) Does Espanola Hydro use the same process to read all meters regardless of capacity? If not, please provide a breakdown of meter reading costs, by rate class used to derive the weighting factor.

Response:

a) Please see Table Staff-32 below for the derivation of the services weighting factors. This update in service weighting factors will be adjusted in the revised cost allocation model submitted with the IR response.

Table Staff-32 – Derivation of Services Weighting Factors

Espanola 2021 COS Application												
	Residential OH	Residential UG	**Residential Total**	<50kW OH	<50kW UG	**<50kW Total**	>50kW OH	>50kW UG	**>50kW Total**	**Streetlights**	**Sentinel Lights**	**Unmetered**
quantity of connectioncs	1450	1451		127	253		3	25				
Approx. $/Connection	$ 982.00	$ 1,398.00		$ 982.00	$ 869.00		$ 484.00	$ 869.00		$ 146.00	$ 146.00	$ 146.00
Value	$ 1,424,391.00	$ 2,027,799.00	$ 3,452,190.00	$ 124,714.00	$ 219,857.00	$ 344,571.00	$ 1,452.00	$ 21,725.00	$ 23,177.00	$ 403,500.00	$ 600.00	$ 1,100.00
Avg Asset Cost			$ 1,190.00			$ 906.77			$ 827.75	$ 146.00	$ 146.00	$ 146.00
CIS # Services			2901			380			28	1062	34	21
Total Value			$ 3,452,190.00			$ 344,571.00			$ 23,177.00	$ 155,052.00	$ 4,964.00	$ 3,066.00
% of total			86.67%			8.65%			0.58%	3.89%	0.12%	0.08%
Value of 1855			$ 312,517.40			$ 31,193.08			$ 2,098.15	$ 14,036.44	$ 449.38	$ 277.56
Historical Avg Cost of Service			$ 107.73			$ 82.09			$ 74.93	$ 13.22	$ 13.22	$ 13.22
Ratio of Avg Asset Cost			1			0.8			0.7	0.1	0.1	0.1
Ratio of Hist Avg Cost of Service			1.00			0.76			0.70	0.12	0.12	0.12
OEB 1855 Value	$ 360,572.00											

Residential Overhead

The ownership demarcation point for residential Rate Class customers supplied by an overhead secondary service is immediately past the connectors at the top of the service mast. ERHDC owns and is responsible for maintenance of the system up to and including the connectors at the ownership demarcation point.

The standard Overhead Secondary Service for customers requiring up to 200 Amp Overhead Service includes 30 meters of supplied and installed overhead triplex. The customer contributes $383.00 plus HST. Services beyond 30 meters are charged an additional $5.53 per meter plus HST.

Residential Underground

The ownership demarcation point for Residential Rate Class customers served via an underground secondary service is immediately past the line side lugs (but not including the lugs) on the meter base. ERHDC owns and is responsible for maintenance of the system up to but excluding the meter base lugs at the ownership demarcation point.
The standard underground Secondary Service for customers requiring up to a 200 Amp underground service from an existing pole is based on 20 meters of 3/0 aluminum underground cable. The customer contributes $373.00 plus HST. Services beyond 20m are charged an additional $7.83 plus HST per meter.

Standard Overhead Connection General Service Rate Class Under 50 KW

The ownership demarcation point for General Service Rate Class Under 50 KW customers supplied by an overhead secondary service is immediately past the connectors at the top of the service mast. ERHDC owns and is responsible for maintenance of the system up to and including the connectors at the ownership demarcation point.

Basic connection is Single phase, 120 / 240 v, max 200 Amps includes up to 30 meters of 1/0 overhead triplex. The customer contributes $547.00 plus HST. Services beyond 30meters are charged an additional $5.53 per meter plus HST. Additionally there are variable transformer charges based on service breaker / fuse size. (Ex 15Amp = $161.28 + HST, 200 Amp =$2150.40 + HST)

Standard Underground Connection General Service Rate Class Under 50 KW

The ownership demarcation point for General Service Rate Class Under 50 KW customers supplied by an underground secondary service is immediately past the connectors at the utility owned pole or transformer. ERHDC owns and is responsible for maintenance of the system up to and including the connectors at the ownership demarcation point.

The standard underground service for general service Rate Class customers <50 KW requiring up to and including 200 Amp Underground is Customer Owned and installed in accordance with the Ontario Electrical Safety Code and inspected by ESA. The customer contributes $170.00 plus HST. Additionally there are variable transformer charges based on service breaker / fuse size. (Ex 15Amp = $161.28 + HST, 200 Amp =$2150.40 + HST)

Standard Overhead Connection General Service Rate Class Over 50 KW

The ownership demarcation point for General Service Rate Class Over 50 KW customers supplied by an overhead secondary service is immediately past the connectors at the top of the service mast.

Standard connection is Single phase, 120 / 240 v, max 400 Amps includes up to 30 meters of 3/0 overhead triplex. The customer contributes $582.00 plus HST. Services beyond 30meters are charged an additional $6.72 per meter plus HST. Additionally there is a transformer charge of $4300.80 plus HST for a 400 Amp service.

Standard Underground Connection General Service Rate Class Under 50 KW

The ownership demarcation point for General Service Rate Class Over 50 KW customers supplied by an underground secondary service is immediately past the connectors at the utility owned pole or transformer.

The standard underground service for general service Rate Class customers <50 KW requiring up to and including 200 Amp Underground is Customer Owned and installed in accordance with the Ontario Electrical Safety Code and inspected by ESA. The customer contributes $170.00 plus HST. Additionally there is a transformer charge of $4300.80 plus HST for a 400 Amp service.

b) ERHDC uses the AMI for all Time of Use smart meters which are installed for the residential and General Service <50 rate classes. For Large General Service Customers, the meters are manually read but are being transitioned to interval meters and will be read electronically in 2021.

Staff-33 – Rate Design

Reference 1: Revenue Requirement Work Form, Sheet 13. Rate Design

Reference 2: Cost Allocation Model, Sheet O2 Fixed Charge|Floor|Ceiling

Preamble:

Espanola Hydro is proposing to increase the fixed charge for the GS > 50 rate class from $196.43 to $229.37 – this is already above the ceiling of $57.77

Question:

a) Please provide the variable charge that would result from keeping the GS > 50 fixed charge at $196.43.

b) Please provide the variable charge that would result from keeping the GS > 50 fixed charge at $57.77.

Response:

a) The variable charge that would result from keeping the GS>50 fixed charge at $196.43 would be $4.7086/kW

b) The variable charge that would result from keeping the GS>50 fixed charge at $57.77 would be $6.0032/kW.

Staff-34 – Retail Transmission Service Rates

Reference 1: RTSR Model, UTRs and Sub-Transmission

Reference 2: EB-2020-0030, Decision and Rate Order, December 17, 2020

Preamble:

Espanola Hydro has used the 2020 Hydro One Sub-Transmission rates for 2021.

As noted at the second reference, the OEB has approved updated sub-transmission rates for Hydro One Networks Inc. effective January 1, 2021.

Question

a) Please update the RTSR model to reflect the Hydro One Sub-Transmission rates and the UTRs issued on December 17, 2020.

Response:

The RTSR model has been updated to reflect Hydro One Sub-Transmission rates and the UTRs issued on December 17, 2020. The live excel model is titled "ERHDC_2021_RTSR_Workform_20210325".

Staff-35 – Low Voltage Charge

Reference: Exhibit 8, Pages 10-12

Preamble:

As noted in the IR above, the OEB has issued a Decision and Rate Order setting new rates for Hydro One Networks Inc. effective January 1, 2021. OEB staff notes that Espanola Hydro's projected 2021 low voltage costs are based on Hydro One Networks Inc.'s 2020 rates.

Question:

(a) Please update Espanola Hydro's projection of low voltage costs, allocation to rate classes, and corresponding low voltage charges.

Response:

ERHDC has updated its projection of low voltage costs, allocation to rate classes and corresponding low voltage charges in Table Staff-35 below.

Table Staff-35 – Rates – Low Voltage Adjustment

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	218,049	32,702,467		kWh	0.0067	
GS < 50 kW	61,274	10,389,919		kWh	0.0059	
GS >50 to 4999 kW	89,764	15,417,468	38,397	kW		2.3378
Sentinnel	124	24,151	67	kW		1.8371
Street Lighting	1,188	224,919	660	kW		1.7996
Unmetered and Scattered	693	119,334		kWh	0.0058	
TOTALS	**371,092**	**58,878,258**	**39,124**			

Staff-36 – Regulatory Charges

Reference 1: Exhibit 8, Page 9

Reference 2: Tariff of Rates and Charges

Preamble:

The tariff of rates and charges includes a Wholesale Market Service (WMS) Rate of $0.0034 / kWh. This is comprised of two charges, WMS and Capacity Based Recovery (CBR).

Question:

(a) Please work with OEB staff to revise the tariff to reflect the two separate charges.

Response:

a) The Schedule of Tariff of Rates and Charges has been updated to reflect the separation of the Wholesale Market Service Rate and the Capacity Based Recovery rate. The new model also has additional updates based on the changes outlined in OEB Staff-1. The live excel version has been filed with the IR Responses.

Staff-37 – Loss Factor

Reference 1: Chapter 2 Appendix 2-R

Reference 2: Tariff of Rates and Charges

Preamble:

Espanola Hydro indicated that it experienced loss factors of 1.0399 in 2015, 1.0566 in 2016, and in each year from 2017 to 2019, the loss factor was at least 1.0800.

OEB staff has compared the Wholesale kWh A(1) to the RRRs:

	Appendix 2-R	RRRs	Variance
2015	61,027,107	60,115,154	911,953
2016	59,711,876	59,057,437	654,439
2017	58,757,254	58,172,799	584,455
2018	60,659,212	59,752,614	906,598
2019	61,089,144	59,963,198	1,125,946

OEB staff has compared the Retail kWh from row D to the RRRs:

	Appendix 2-R	RRRs	Variance
2015	58,759,087	58,365,911	393,176
2016	56,644,799	56,279,165	365,634
2017	55,047,910	54,516,683	531,227
2018	57,210,184	56,923,775	286,409
2019	57,482,828	57,288,172	194,656

The proposed tariff of rates and charge indicates a secondary loss factor of 1.0673, and a primary loss factor of 1.0573. It also indicates a primary metering allowance of 1.00%

The secondary loss factor of 1.0673 divided by 1.01 (accounting for the 1% primary metering adjustment) is 1.0567.

Question:

(a) Please explain the causes of the increase in losses from the 2015-2016 period to the 2017-2019 period.

(b) Please reconcile the differences between the quantities in Chapter 2 Appendix 2-R and the RRR filings.

(c) Please explain how the primary loss factor of 1.0573 was arrived at as opposed to the more conventional 1.0567 that would result from a secondary loss factor of 1.0673.

Response:

a) ERHDC has extensively investigated the reason for the system losses in all years. A review has been done of the metered consumption, a reconciliation of hydro one invoices, and the amount of embedded generation. However, ERHDC is not able to determine the cause of the fluctuations in system losses.

b) The variance reported in the OEB Staff's first table is due to the request of different information. ERHDC understands the RRR filing to ask for supply, net of losses. Appendix 2-R part A(1) asks for amount delivered with losses. Therefore, the variance reported in the OEB Staff's first table would be the losses attributable to Hydro One's system.

The second table provided by OEB Staff no longer has any variance. ERHDC revised its RRR filing on February 4, 2021. Please see reconciliation in Table Staff-37 below.

Table Staff-37 – Reconciliation with RRR

	Appendix 2-R	RRRs	Variance	RRR Revised	LTLT	Total	New Variance
2015	58,759,087	58,365,911	393,176	58,546,507	212,588	58,759,095	- 8
2016	56,644,799	56,279,165	365,634	56,468,304	178,345	56,646,649	- 1,850
2017	55,047,910	54,516,683	531,227	54,871,946	175,647	55,047,593	317
2018	57,210,184	56,923,775	286,409	57,113,840	89,012	57,202,852	7,332
2019	57,482,828	57,288,172	194,656	57,482,817	-	57,482,817	11

c) The primary loss factor was calculated incorrectly. Therefore the 1.0567 that the OEB Staff has calculated should be the accurate primary loss factor.

Staff-38 – Bill Impacts

Reference 1: Exhibit 8, Pages 16-20

Reference 2: Tariff and Bill Impact Model, sheet 6. Bill Impacts

Preamble:

Three strategies to mitigate bill impacts are proposed including moving the sentinel lighting revenue to cost ratio only to 80%, rather than increasing to the same level as Residential. Despite this, the sentinel rate class has a total bill impact before taxes of $2.97, or 15.21%. The bill impact is a result of an increase of $3.53 to distribution charges, partially offset by rate riders.

Question:

(a) Has Espanola Hydro considered phasing in the increase to 80% revenue-to-cost over a period of more than one year as an additional form of mitigation?

(b) Has Espanola Hydro informed its sentinel light customers of the expected increase?

(c) Please discuss why further rate mitigation for the sentinel light rate class is not necessary.

Response:

a) ERHDC considered phasing in all rates over a period of 2 years so that the Revenue to Cost Ratio's would be within policy range by 2023. However, due to some of the adverse impacts and variability in other rate classes, ERHDC did not propose this option as a viable rate mitigation option. ERHDC did not look at phasing in the increase for only the Sentinel Light Class as the total revenue requirement for that class is $4,131. It was determined to be more of an administrative burden in tracking than the overall increase of $2.37.

b) ERHDC has not informed its Sentinel Light customers of the expected increase.

c) Overall a Sentinel Light customers bill is going up $2.37. Although this represents a 15.21% increase, it is not a large dollar value. ERHDC wanted to keep rate mitigation strategies uniform across all rate class as to ease future administrative burden.

Staff-39 – Bill Impacts

Reference 1: Exhibit 8, Page 20

Reference 2: Exhibit 6, Page 4

Preamble:

Espanola Hydro stated that the greater than 10% bill impact to its low volume residential customers is mainly due to the change in the cost allocation model for the street lighting class (due to the OEB's change in cost allocation policy for the street lighting class on June 12, 2015) and the fixed/variable transition.

OEB staff notes that Espanola Hydro's revenue requirement underpinning its base rates has increased significantly since its last rebasing. According to reference 2, there is a revenue deficiency of $449,736, or increase of 25% above estimated 2021 revenues at existing rates.

Question:

(a) Please provide an estimate and breakdown of the effect on the bill impact of the following components on low volume residential customers: the fixed/variable transition, cost allocation policy changes, and increase in revenue requirement.

(b) To the extent that the bill increase is caused by Espanola Hydro's proposed increase in revenue requirement, please discuss whether it would be appropriate for further rate mitigation measures for the residential rate class.

Response:

a) ERHDC has provided the following Table Staff-39 as a summary of the breakdown requested. The different effects are shown as a progression. First the increase in revenue requirement represents a bill increase of 4.50%. Secondly the revenue requirement and change in cost allocation policy represents a bill impact of 6.94%. Lastly the increase in revenue requirement, cost allocation policy and a 5-year fixed to variable transition represents a bill impacts of 10.75%.

Table Staff-39 – Summary Breakdown of Bill Impacts

		Revenue Requirement	Fixed	Variable	Bill Impacts
A)	Increase in Revenue Requirement Cost Allocations Perecentages (Sentinel Light 80%, GS>50 = 120%, Street =203.9) No Fixed to Variable Transition	$1,358,899.00	18.28	0.0177	4.50%
B)	Increase in revenue requirement Cost Allocation Percentages within Policy No Fixed to Variable Transition	$1,381,388.00	18.58	0.0224	6.94%
C)	Increase in Revenue Requirement Cost Allocation Percentage within Policy 5 Year F/V Transition	$1,381,388.00	22.77	0.018	10.75%

b) Since ERHDC increase in revenue requirement only represents 4.50% of the 10.75% increase in bill impacts, ERHDC believes no further rate mitigation measures are needed for the residential class.

Staff-40 – Deferral and Variance Accounts

Reference 1: Exhibit 9, Page 10

Reference 1: DVA Continuity Schedule

Preamble:

Typically, large balances are not expected for Account 1588 as it should only hold the variance between commodity costs based on actual line losses and commodity revenues calculated using values for line losses as approved by the OEB in the utility's last rebasing application. Based on RRR data filed for ERHDC for Account 4705 Cost of Power, OEB staff calculates the annual net activity (i.e. transactions plus principal adjustments) from the DVA Continuity Schedule as a percentage of annual Account 4705 to be as follows:

	Net Activity in Account 1588 ($)	Account 4705 ($)	% of net activity compared to Account 4705
2019	(96,681)	5,885,077	-1.6%
2018	(174,291)	5,446,768	-3.2%
2017	193,301	6,034,566	3.2%
2016	(38,418)	6,697,627	-0.6%
2015	345,897	6,222,538	5.6%
Cumulative	**229,808**	**30,286,576**	**0.8%**

Question:

(a) Please confirm this calculation or provide a revised calculation.

(b) For year(s) where the percentage is greater than +/-1%, please provide an explanation as to why the Account 1588 activity would be high in consideration of line losses.

Response:

a) ERHDC was last approved for disposition of account 1588 in the 2015 rate year (2013 balances). Therefore, ERHDC has provided a revised chart to include 2014 Net activity. ERHDC did a further review into its 1588 account balances and determined there was additional adjustments shown below. A revised DVA continuity schedule is provided at Table Staff-40 below.

Table Staff-40 –Revised DVA Continuity Schedule

	Net Activity in Account 1588 ($)	Adjustment	Revised Net Activity in 1588 ($)	Account 4705 ($)	Revised % of net activity compared to account 4705
2019	(96,681.00)		(96,681.00)	5,885,077.00	-1.64%
2018	(174,291.00)	44,621.05	(129,669.95)	5,446,768.00	-2.38%
2017	193,301.00	(74,079.63)	119,221.37	6,034,566.00	1.98%
2016	(38,418.00)	17,190.57	(21,227.43)	6,697,627.00	-0.32%
2015	345,897.00	(130,318.47)	215,578.53	6,222,538.00	3.46%
2014	(114,674.77)	3,652.44	(111,022.33)	5,918,931.28	-1.9%
Cumulative	115,133.23	(138,934.04)	(23,800.81)	36,205,507.28	-0.07%

b) Corrections were made in years 2014 through 2018 which can be viewed in the adjustments column. Moving forward changes to the variance reporting process have now been made according to the accounting guidance, allowing ERHDC to reconcile and explain any unusually large variances going forward. In the revised table above the cumulative variance from 2014 through 2019 is -0.07%.

Staff-41 – Deferral and Variance Accounts

Reference 1: Exhibit 9, Page 4

Reference 2: DVA Continuity Schedule

Preamble:

At the above-noted reference, Espanola Hydro stated:

A clerical error was spotted in 2015 that has resulted in a net adjustment of -$258,839 in account 1588 and $258,839 in account 1589. Subject to this correction, ERHDC has complied with the OEB guidance of February 21, 2019 on the accounting for accounts 1588 and 1589.

Question:

(a) Please explain in further detail the nature of the error and what measures or process changes have been implemented to prevent similar errors from repeating.

Response:

a) The error was a simple clerical error when there should have been a rate entered in as negative it was entered in as positive. ERHDC has not had any such error since due to multiple checks that have been put in place to prevent further clerical errors.

Staff-42 – Deferral and Variance Accounts

Reference 1: Exhibit 9, Page 4

Reference 2: DVA Continuity Schedule, Tab 2a

Preamble:

OEB staff notes that there are no recorded amounts under account 1580 – sub-account CBR Class B. As per the OEB's accounting guidance issued on July 25, 2016 (https://www.oeb.ca/oeb/_Documents/Regulatory/CBR_Accounting_Guidance_20160725.pdf), distributors are expected record CBR charges, costs, and variances in separate sub-accounts starting January 1, 2016.

Question:

(a) Please clarify if there are no variances for the CBR component, or if the CBR variances are currently recorded as part of the balance of the general WMS account 1580.

(b) If the latter, please explain why Espanola Hydro has not followed the OEB's July 25, 2016 accounting guidance.

Response:

a) The CBR variance are currently recorded as part of the balance of the general WMS account.

b) ERHDC bills both the WMS and the CBR component as one rate in the billing system. Therefore, to separate out the small difference related to just the CBR component would be very difficult as well as immaterial. Thus, ERHDC chose to keep the 2 rates as one.

Following approval of this rate application, ERHDC will track WMS and CBR components separately going forward.

Consumers Council of Canada Interrogatories

CCC-1

Question:

Please provide all documents and presentations that were provided to ERHDC's Board of Directors related to this Application, and its approval of this Application, and the underlying budgets.

Response:

The documents provided to ERHDC's Board of Directors related to this application is provided in Appendix 2 – Board Presentation.

<u>CCC-2</u>

Reference: Ex. 1/p.8

Preamble: N/A.

Question:

Please explain why ERHDC did not choose to rebase its 2012 rates earlier. Please explain why the actual ROEs in the years 2016-2020 were significantly less than the Board approved levels whereas in earlier years the ROEs were much higher. What was EERHDC's actual ROE for 2020?

Response:

ERHDC was one of the distributors scheduled to apply to have rates rebased in 2016. ERHDC requested and was granted permission to defer its application beyond the 2016 rate year. At the time, due to limit resources, it was ERHDC's determination that a full cost of service application for 2016 rates may not be the most efficient use of resources to best serve customers. ERHDC's service quality, customer satisfaction, safety and system reliability performance all met or exceeded targets for 2014 and 2015 and ERHDC continued to be ranked in group 2 in the OEB's efficiency assessment. While ERHDC's return on equity was high for 2014 and 2015, this was due to rate riders for the recovery of residual historical smart meter costs, recovery of stranded meters, recovery of LRAM and recovery of forgone revenue that were due to expire in April of 2016. The projected return on equity for 2016 was 7.53% (actual was 6.29%). The OEB responded that it would not require ERHDC's 2016 rates to be set on a cost of service basis. With the commencement of the process to sell ERHDC in early 2017 the rate request process was put on hold. The sale process eventually concluded in October 2019.

For a detailed breakdown in the fluctuations of ROE from 2014 through 2019 see OEB Staff-2. The preliminary calculations in actual 2020 ROE for ERHDC is -14.78%

CCC-3

Reference: Ex1/p. 8

Preamble:

ERHDC is seeking recovery of regulatory costs related to its Application of $582,539:

Question:

a) Has ERHDC benchmarked these costs and compared them to other LDCs. If so, please provide the results of the benchmarking. If not, why not?

b) Were the consulting costs and legal costs (for the Application and the DSP) subject to an RFP process? If not, why not? Please provide the terms of reference for this work.

Response:

a) ERHDC did benchmark these costs to PUC Distribution Inc., Greater Sudbury Hydro, Niagara Peninsula Energy Inc. and North Bay Hydro Distribution Ltd. The results are provided in Table CCC-3 below.

Table CCC-3 – Benchmarking Results for Regulatory Costs

		ERHDC	PUC 2018	Sudbury 2019	North Bay 2021	NPEI 2020
Legal	Application	$100,000	$179,582	$60,000		$200,000.00
	Settlement and IRR	$50,000	$76,078			
Indeco		$10,000	$11,169		$626,300.00	
Metsco	Consultants	$65,000	$100,000	$220,000		$289,451.00
Finance Consultant		$282,539	$0			
	VECC		$16,550			
Intervenors	SEC	$50,000	$23,716	$60,000	$85,000.00	$72,000.00
	CCC		$15,354			
Internal Additional Labour		$0	$405,760	$95,000	$82,250.00	
Settlement Conference Expenses		$5,000	$10,000	$15,000	$0	
OEB Costs		$20,000	$0	$0	$0	$22,000.00
Total		**$582,539**	**$838,209**	**$450,000**	**$793,550**	**$583,451**

b) PUC Services. is responsible for the management services contract with ERHDC. Therefore, they would have the most knowledge of the background information in regards to compiling all the financials needed for the application. If a third party was considered for the application, it would have taken both PUC Services and that third party to work collaboratively in order to complete the application. ERHDC believed that this would only further add to the costs required to complete the application. Additionally, the same applies to legal services as BLG has represented ERHDC in past proceedings. To involve a different legal party at this point would add further legal costs. Therefore, an RFP process was not undertaken for both consulting and legal costs.

CCC-4

Reference: Ex 1/p. 11

Preamble: N/A.

Question:

Please provide the amounts recorded in each of the Account 1509 sub-accounts, and the amounts expect to be recorded going forward. Please provide all assumptions.

Response:

Account 1509 – Impacts Arising from the COVID-19 Emergency, Sub-account Costs Associated with Billing and System Changes

ERHDC has not recorded any expenses associated with billing and system changes to date.

Account 1509 – Impacts Arising from the COVID-19 Emergency, Sub-account Lost Revenues

ERHDC has not recorded any expenses associated with lost revenues to date.

Account 1509 – Impacts Arising from the COVID-19 Emergency, Sub-account Other Costs

ERHDC has recorded $20,702 in this account for additional PP&E expenses, computer equipment for setting up employees to work from home, management labour time dedicated to addressing COVID impacts, and costs associated with keeping employees safe. ERHDC expects to record similar costs as the pandemic continues.

ERHDC has not recorded a material increase to its Bad Debt provision related to COVID to date.

CCC-5

Reference: Ex 1/p. 39

Preamble: N/A

Question:

Please set out the distribution rate increases in each year 2013-2021 for each customer class. What are the increases expected to be from 2021-2025 assuming the OEB approves the move to full fixed charges as proposed? What are the expected annual increases 2021-2025 including the DVA rate riders?

Response:

The distribution rate increases in each year from 2013 to 2021 are provided in the Table CCC-5 below.

Table CCC-5-1 – Distribution Rate Increases from 2013 to 2021

Rate Class	2013		2014		2015		2016-2020		2021	
	fixed	variable	fixed	variable	fixed	variable	fixed	variable	fixed	variable
Residential	$ 0.07	$ 0.0001	$ 1.60	$ 0.0037	$ 0.20	-$ 0.0015	$ -	$ -	$ 7.31	-$ 0.0007
GS<50	$ 0.12	$ 0.0001	$ 2.86	$ 0.0023	$ 0.36	$ 0.0003	$ -	$ -	$ 4.52	$ 0.0037
GS>50	$ 0.91	$ 0.0236	$ 22.30	$ 0.4307	$ 2.81	$ 0.0542	$ -	$ -	$ 13.60	$ 0.2326
USL	$ 0.06	$ 0.0001	$ 1.39	$ 0.0018	$ 0.18	$ 0.0002	$ -	$ -	$ 2.19	$ 0.0028
Street Light	$ 0.01	$ 0.1163	$ 0.23	$ 2.8466	$ 0.03	$ 0.3585	$ -	$ -	-$ 0.90	-$ 11.3453
Sentinel Light	$ 0.01	$ 0.0800	$ 0.24	$ 1.9587	$ 0.03	$ 0.2467	$ -	$ -	$ 1.05	$ 8.4779

If the OEB approves the move to fully fixed charges the increases expected for the residential class are shown in the following Table CCC-5-2:

Table CCC-5-2 – Increases Expected for Residential Class Resulting from Fully Fixed Charge

Rate Class	2021		2022		2023		2024		2025	
	fixed	variable	fixed	variable	fixed	variable	fixed	variable	fixed	variable
Residential	$ 7.31	-$ 0.0007	$ 4.20	-$ 0.0045	$ 4.20	-$ 0.0045	$ 4.19	-$ 0.0045	$ 4.20	-$ 0.00

If the proposed DVA rate riders proposed as part of this Cost of Service application are approved it would result in the following annual increases as shown in Table CCC-5-3. Please note that this does not take into account any future potential rate riders.

Table CCC-5-3 – Annual Increases Resulting from DVA Rate Riders

Rate Class	2021		2022		2023		2024		2025	
	fixed	variable	fixed	variable	fixed	variable	fixed	variable	fixed	variable
Residential	$ 5.63	$ 0.00	$ 5.88	-$ 0.00	$ 4.20	-$ 0.00	$ 4.19	-$ 0.00	$ 4.20	-$ 0.00
GS<50	$ 4.52	$ 0.01	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -
GS>50	$ 13.60	$ 1.15	$ -	$ 0.33	$ -	$ -	$ -	$ -	$ -	$ -
USL	$ 2.19	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -
Street Light	-$ 0.90	$ 19.32	$ -	$ 2.92	$ -	$ -	$ -	$ -	$ -	$ -
Sentinel Light	$ 1.05	$ 8.90	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -

CCC-6

Reference: Ex 1/p. 38

Preamble: N/A

Question:

ERHDC is moving to fully fixed rates for residential customers over the next five years. Has ERHDC undertaken any communication plans regarding the change? If so, please describe the plans. If not, why not? What type of communication is being planned for the May 1, 2021 rate changes?

Response:

ERHDC has not yet communicated with its residential customers regarding the transition to fully fixed rates, because ERHDC's proposal to do this over the next five years is not yet approved by the OEB.

In terms of customer engagement undertaken prior to the filing of the application, there are many drivers associated with how ERHDC communicates with customers. ERHDC generally focuses on the changes that are within its control to obtain customer preferences. Drivers such as transition to fully fixed rates are not within ERHDC's control. It is a regulatory impertative.

ERHDC plans to communicate additional material on the upcoming changes for residential customers following approval of this rate application. The specifics on how to effectively reach customers has not yet been determined.

CCC-7

Reference: Ex. 1/p. 60

Preamble: N/A

Question:

The evidence states that in 2019 ERHDC had increased costs due to higher administration costs from the sale of ERHDC to North Bay Hydro. Were these all one-time costs?

Response:

The increased costs due to the sale of ERHDC to North Bay Hydro were approximately $100,000. These were one-time costs that are not funded through rates and are not included in 2021 Test Year request.

CCC-8

Reference: Ex. 1/p. 68

Preamble: N/A

Question:

When do ERHDC and North Bay Hydro intend to harmonize their rates? Is this likely to result in an increase or decrease for ERHDC customers?

Response:

ERHDC and North Bay Hydro are separate legal entities, and therefore no rate harmonization is necessary at this point.

With respect to the potential future merger of ERHDC and North Bay Hydro and what may occur as a result of the merger, ERHDC is of the view that it is not relevant to this proceeding.

As provided in OEB's Decision on Issues List for ERTH Power Corporation's 2018 Cost of Service Application (EB-2017-0038):[3]

"The setting of just and reasonable rates in this proceeding is not modified by considerations of what might eventuate in a future MAADs decision. The OEB finds that potential cost savings arising from the proposed amalgamation of ETPL with West Coast Huron Energy Inc., are outside the scope of this proceeding."

In another decision of the OEB, PowersStream Inc. 2016 Cost of Services Application (EB-2015-0003), the OEB made a similar finding:[4]

"the OEB considers that evidence on potential cost savings due to the merger regardless of substance, is outside the scope of this proceeding."

In a similar vein, the potential harmonization of rates following a potential merger that has not yet happened is outside of the scope of this proceeding.

[3] EB-2017-0038 - ERTH Power Corporation 2018 Cost of Service Application – Decision on Issues List dated August 9, 2018, at page 9.
[4] EB-2015-0003 – PowerStream Inc. – Decision on Threshold Question and Procedural Order No. 5 dated October 6, 2015 at pages 6 to 8.

CCC-9

Reference: Ex.2, Appendix 2-AA

Preamble: N/A

Question:

a) Please add 2016 data to Appendix 2-AA.

b) Please update capital 2020 as required.

Response:

a) 2016 data has been added to Appendix 2-AA – see below.

b) 2020 data has been updated in Appendix 2-AA – see below.

Appendix 2-AA
Capital Projects Table

Projects	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
Reporting Basis						
Pole Replacements						
Distribution Stations						
Poles, Towers, Fixtures	22,184	64,088	96,375	190,196	39,446	75,615
O/H Conductors & Devices	6,744		3,634	28,677	924	
Underground Conduit						
U/G Conductors & Devices	737			6,548	145	
Line Transformers	11,231				3,090	
Services - New	16,727		158			
Meters	3,504					
Sub-Total	61,126	64,088	100,167	225,421	43,606	75,615
OH Cutout Renewal		3,689	9,037	4,663		9,547
Distribution Stations						
Poles, Towers, Fixtures						
O/H Conductors & Devices						
Underground Conduit						
U/G Conductors & Devices						
Line Transformers						
Services - New						
Meters						
Sub-Total	0	3,689	9,037	4,663	0	9,547
Spnaish River Drive				3,706		
Distribution Stations						
Poles, Towers, Fixtures					20,204	
O/H Conductors & Devices					71	
Underground Conduit					46,893	
U/G Conductors & Devices					5,476	
Line Transformers					11,821	
Services - New					19,395	
Meters					391	
Sub-Total	0	0	0	3,706	104,251	0
Massey 3 Phase Line Replacement						
Distribution Stations						
Poles, Towers, Fixtures						42,984
O/H Conductors & Devices						42,984
Underground Conduit						
U/G Conductors & Devices						
Line Transformers						15,170
Services - New						25,285
Meters						
Sub-Total	0	0	0	0	0	126,423
Duplessis road pole Line rebuild					41,400	
Distribution Stations						
Poles, Towers, Fixtures						
O/H Conductors & Devices						
Underground Conduit						
U/G Conductors & Devices						
Line Transformers						
Services - New						
Meters						
Sub-Total	0	0	0	0	41,400	0
Cross Lot Relocations		39,070			1,215	
Distribution Stations						
Poles, Towers, Fixtures			38,491	42,827		
O/H Conductors & Devices			38,163	34,130		
Underground Conduit						
U/G Conductors & Devices			141	4,807		
Line Transformers			2,737			
Services - New						
Meters						
Sub-Total	0	39,070	79,532	81,764	1,215	0

Double Bucklet Truck						
Distribution Stations						
Poles, Towers, Fixtures						
O/H Conductors & Devices						
Underground Conduit						
U/G Conductors & Devices						
Line Transformers						
Services - New						
Meters						
Vehicles				70,339		
Sub-Total	0	0	0	70,339	0	0
Replace Submarine Cable						
Distribution Stations						
Poles, Towers, Fixtures						
O/H Conductors & Devices						
Underground Conduit						
U/G Conductors & Devices		61,733	184,153			
Line Transformers						
Services - New						
Meters						
Sub-Total	0	61,733	184,153	0	0	0
Conductor Replacements - Tie Feeders F3-F5						
Distribution Stations						
Poles, Towers, Fixtures		39,389				
O/H Conductors & Devices		128,691				
Underground Conduit		0				
U/G Conductors & Devices		5,056				
Line Transformers		3,367				
Services - New		0				
Meters		0				
Sub-total	0	176,503	0	0	0	0
Conductor Replacements - Tie Feeders F1-F8						
Distribution Stations						
Poles, Towers, Fixtures	30,009	4,782				
O/H Conductors & Devices	121,638	77,844				
Underground Conduit		0				
U/G Conductors & Devices		13,878				
Line Transformers		0				
Services - New	2,076	0				
Meters		0				
Sub-Total	153,724	96,504	0	0	0	0
44kV Loop						
Distribution Stations						
Poles, Towers, Fixtures	6,207					
O/H Conductors & Devices	26,558					
Underground Conduit						
U/G Conductors & Devices	12,900					
Line Transformers	13,244					
Services - New	8,608					
Meters						
Sub-Total	67,517	0	0	0	0	0
Clear Lake						41,821
Distribution Stations						
Poles, Towers, Fixtures					55,797	
O/H Conductors & Devices					9,135	
Underground Conduit					155	
U/G Conductors & Devices					42	
Line Transformers					5,770	
Services - New					259	
Meters					15	
Sub-Total	0	0	0	0	71,173	41,821
Long Term Load Transfer						
Distribution Stations		55,212				
Poles, Towers, Fixtures		77,380				
O/H Conductors & Devices		0				
Underground Conduit		0				
U/G Conductors & Devices		26,666				
Line Transformers		2,404				
Services - New						
Meters						
Sub-Total	0	161,662	0	0	0	0
Miscellaneous						
Misc. Facilities	3,019				35,594	25,000
Land						
Vehicle	43,617				10,639	
Tools and Equipment	4,658			7,166	5,237	8,000
IT Equipment				7,759	11,195	
New & Upgrade Services	31,440	16,460	37,030	18,643	36,427	25,027
Sacred Heart School Service		661	111	18,028		
Joint Use Poles				0		2,656
City Projects - line relocations				0	269	7,762
Meters		3,024		0	17,396	16,419
MIST Meters					15,855	
OH Transformer Renewal	5,238	18,468	16,612	21,996	21,550	40,654
Clearlake						
Brentwood Subdivision				1,459	30,360	
OH Forced Outages					13,156	5,587
Kbar Replacement					859	12,268
Transclosure Replacement						38,795
UG Forced Outages			3,536		12,043	2,925
MS 3 Conductor Replacement						46,318
Insulator Replacement					20,614	
Substation Misc. Projects					2,695	3,612
Spruce Street Project					41,060	
Mead Project	40,177					
4kV Feeder at MS 2	15,887	6,813				
Miscellaneous Subtotal	144,036	45,426	57,289	75,051	274,949	235,023
Total	426,403	648,675	430,178	460,944	536,594	488,429

CCC-10

Reference: Ex. 2, Appendix B, DSP p. 21 Table 2-9

Preamble: N/A

Question:

Please explain the significant increase in Scheduled Outages in 2019.

Response:

The increase in scheduled outages in 2019 are a result of overhead transformer replacements and deteriorated pole replacements. In 2019, ERHDC began the removal of overhead transformers containing PCB levels greater than 50 PPM. Six transformers were replaced requiring scheduled outages. Deteriorated pole changes in 2019 included two poles with overhead transformers, and three poles with underground secondary services. Scheduled outages were required to transfer the transformers and underground services to new poles.

CCC-11

Reference: Ex. 2, Appendix B, DSP p. 61 Table 4-2

Preamble: N/A

Question:

a) Please add 2016 data to Table 4-2.

b) Please update 2020 capital data as required.

Response:

a) 2016 data has been added to Appendix 2-AB and Table 4-2 – see below.

b) 2020 data has been added to Appendix 2-AB and Table 4-2 – see below.

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2021*

CATEGORY	Historical Period (previous plan[1] & actual)																		Forecast Period (planned)
	2012			2016			2017			2018			2019			2020			2021
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var	
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000
System Access	68	87	27.9%	91	31	-65.4%	242	182	-25.0%	109	37	-65.8%	108	38	-64.7%	148	91	-38.6%	52
System Renewal	779	835	7.2%	554	347	-37.4%	454	467	2.9%	446	393	-11.9%	417	338	-19.0%	502	383	-23.8%	404
System Service			--			--			--			--			--			--	
General Plant	195	20	-89.7%	476	48	-89.9%	415	-	-100.0%	13	-	-100.0%	13	85	582.1%	58	63	8.0%	33
TOTAL EXPENDITURE	1,042	942	-9.6%	1,120	426	-61.9%	1,111	649	-41.6%	567	430	-24.2%	537	461	-14.2%	708	537	-24.3%	488
Capital Contributions	16	71	330.9%	13	47	264.1%	18	3	-82.1%	24	40	70.8%	30	39	32.7%	64	5	-91.9%	25
Net Capital Expenditures	1,026	871	-15.1%	1,107	379	-65.8%	1,093	646	-40.9%	544	390	-28.3%	507	422	-16.9%	645	531	-17.6%	463
System O&M	$ 647	$670	3.6%	$ 631	$647	2.5%	$ 647	$586	-9.4%	$649	$641	-1.3%	$688	$720	4.7%	$723	$ 717	-0.9%	$ 735

CCC-12

Reference: Ex. 2, Appendix C Overhead Renewal – Poles Job #70 System Renewal

Preamble: N/A

Question:

a) Please provide the number of poles replaced in each of the years 2016 to 2020.

b) Please provide the number of poles in poor and very poor condition from the 2015 Asset Condition Assessment (ACA) and in 2020.

c) Please provide the condition of the 10 poles to be replaced in 2021.

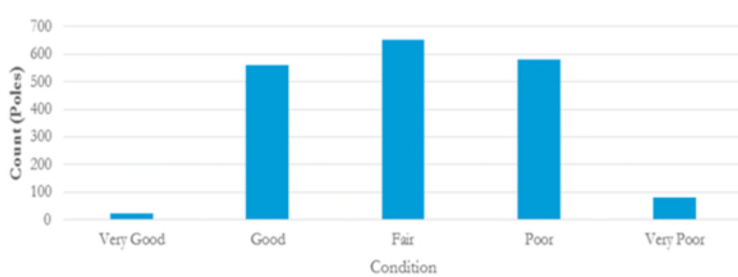
Response:

a) The following is a list of the number of poles replaced as part of ERHDC's deteriorated pole renewal plans for the years 2016 through 2020:

Year	Poles Replaced
2016	5
2017	18
2018	18
2019	9
2020	2

b) As indicated in Figure CCC-12 below, there were 580 poles classified as "Poor" and 80 poles classified as "Very Poor" in the 2015 Asset Condition Assessment.

Figure CCC-12 – Wood Poles Condition Assessment



There has not been a formal Asset Condition Assessment plan prepared in 2020, however the following condition estimates are provided based on our ongoing inspection and maintenance activities. (i.e.: annual non-destructive pole testing, one-third plant inspection, field staff inspections performed in the course of other duties). It is estimated that there are 630 poles in ERHDC's distribution system in "Poor" condition, and 50 poles in "Very Poor" condition.

c) As pole replacements are in part, in response to our inspection programs, to date we have identified 7 poles for replacement in 2021. Non-destructive pole testing and one-third plant inspection have yet to be completed in 2021. As our pole replacement program aims to addresses poles with the most urgent need of replacement, the 7 poles due to be replaced are classified as "Very Poor" condition.

CCC-13

Reference: Ex. 2, Appendix C Massy Line Rebuild Job #71 System Renewal

Preamble: N/A

Question:

a) Please provide a summary of the equipment to be replaced as part of the Massy Line Rebuild.

b) Please provide the condition assessment of the equipment to be replaced.

Response:

a) The equipment to be replaced as part of the Massy Line Rebuild, including new equipment to be installed is listed below:

Poles	16 replacements, 15-45'Cl3, 1-35'Cl3, and an additional 45' Cl3 for guying (push brace)
Insulators	18 replacements, 32 new installations
X-arms	3 replacements, 2 new installations
Secondary Bus	550m of 1c 1/0, 2 c3/0 triplex to be replaced with 3/0 AACSR lashed with 500m 266 Al secondary conductor
Primary conductor	310m single phase #2 ACSR conductor to be removed and replaced with 550m three phase 3/0 ACSR
Switches & Arrestors	5 fused cutouts and 2 arresters replaced

b) Based on pole testing data, age, and annual one-third plant inspections, insulators, crossarms, secondary bus, primary conductor, switches and arrestors are classified as poor condition. The existing poles vary in age from 36 to 67 years, with approximately half having been installed in the 1960's and half in early 1980's. Eight poles are classified as poor, with the remaining eight poles are classified as "Fair". Many of the existing primary poles are 35-foot which impede any future expansion/upgrades.

CCC-14

Reference: Ex 2/ p. 39

Preamble: N/A

Question:

ERHDC plans to replace transclosures at a cost of $38,795. Please provide the driver for the replacements and indicate how many are to be replaced.

Response:

The primary driver for replacement of these legacy transclosures is worker safety, with a secondary driver being reliability and the associated direct impact to customers in the form of outages.

A transclosure is essentially a pole-top type distribution transformer installed in a padmounted metalclad enclosure. Due to tight clearances between live parts and the enclosure interior, it is necessary to first isolate this equipment before safely doing any inspections or work on it. Also, because of the legacy type transformers used with side rather than top-mounted bushings, it has become difficult to source spare parts, and there is a requirement to keep units in stock in the event of a failure. Replacing failed units is costly and can require extensive unplanned outages to connected customers in the event of a failure.

Plans are to replace these transclosures with modern dead-front style padmount transformers that will address all the issues with worker safety, availability of replacements and potential customer downtime.

Two transclosures are proposed for replacement in 2021.

CCC-15

Reference: Ex. 2/ p. 39

Preamble: N/A

Question:

ERHDC plans to spend $44,318 on MS 3 conductor replacement.

a) Please provide the drivers for the replacement and the equipment to be replaced.

b) The amount shown for this work in Appendix 2-AA is $46,318. Please reconcile.

Response:

a) The primary driver for replacement of these cables is reliability. The 46kV riser pole supplying Substation MS 3 was replaced as part of a deteriorated pole project in 2019. However, when the pole was replaced, the existing cables did not have sufficient length to be installed on the new pole and were installed on a temporary pole. Temporary overhead 'jumpers' were installed from the temporary pole to the replaced deteriorated pole to restore operation. New 46kV underground primary cables are now to be installed from MS3 to the new riser pole to replace the existing 40 year old cables and allow for the removal of the temporary installation.

b) The correct amount for the MS 3 conductor replacement is $46,318.

CCC-16

Reference: Ex. 2/ p. 39

Preamble: N/A

Question:

ERHDC plans to spend $41,821 on Line replacement at Clear Lake. Please provide the driver for the replacement and the equipment to be replaced.

Response:

The primary drivers for this line replacement project are reliability, public safety, and costs to operate. Since it is in an area difficult to access, addressing outages or conducting repairs or maintenance presents significant cost and time impacts.

A pole on this line was identified through ERHDC's annual pole testing program requiring replacement. Difficulties in accessing the pole location, and a portion of the line crossing a public beach/playground resulted in a decision to relocate this section of line along nearby Foucault Drive. The scope of work includes the replacement of one 50kVA transformer to accommodate a voltage conversion on Foster Drive, the removal of three poles from the shoreline of Clear Lake along with 410m of #2 ACSR primary and neutral conductor, and the transfer/extension of 4 underground services.

CCC-17

Reference: Ex. 4/p. 11

Preamble: N/A

Question:

Please provide a timeline for the development of the budgets underlying this Application**.**

Response:

Work on the 2020 budget commenced in late 2019. The 2020 budget was approved by the ERHDC Board of Directors on February 25, 2020. Upon approval of the 2020 budget, work commenced on the 2021 Test Year budget. The 2021 Test Year budget was provided to the Board of Directors of ERHDC on November 13, 2020, presented formally on November 17, 2020 and approved at that meeting.

CCC-18

Reference: Ex. 4/p. 14

Preamble: N/A

Question:

Of the total OM&A for 2021 how much if it relates to the contract with PUC Services? Are the costs fixed for the rate year, or can the actuals vary? Please explain the extent to which they can vary.

Response:

The contract costs for Billing/Collecting and Management Services are fixed other than the portion based on the number of customers which may fluctuate slightly. Total costs may vary due to work performed outside of the scope of the services contract, such as the Cost of Service application, or other work as agreed upon by the ERHDC owners. Please refer to Staff-28 for the costs associated with the PUC Services contract in 2021.

School Energy Coalition (SEC) Interrogatories

SEC-1

Reference: General

Preamble: N/A

Question:

With respect to the schools served by the Applicant, please confirm:

a. The Applicant currently serves seven schools in three district school boards, and of those schools five are in the GS>50 class and two are in the GS<50 class.

b. The Applicant proposes to increase the annual distribution charges (fixed plus variable plus ICM riders) by about $6,000 a year in this Application, of which $4,500 is an increase for the five GS>50 schools, and $1,500 is an increase for the two GS<50 schools.

c. It is reasonable to anticipate that, when rates are harmonized with North Bay, and given the relative size of the Applicant and North Bay Hydro, as well as the rates for North Bay proposed in EB-2020-0043, the Applicant's schools in the GS>50 class will in aggregate end up with total distribution charges within 5% of the 2021 charges proposed by the Applicant in this Application, while the schools in the GS<50 class will end up with a reduction in annual distribution charges of 15-20%, partially offsetting the increase proposed for this year.

Response:

a) ERHDC could only identify 5 schools of which 4 are in the GS>50 and 1 in GS<50 classes.

b) Using the Tariff Schedule and Bill Impact Model submitted February 23, 2021 as part of OEB Staff Clarification questions, the aggregated annual distribution charges (fixed plus variable ICM rate riders) will increase by $4870. The four GS>50 will receive a total increase of $4000 and the GS<50 will see an increase of $870. Please see supporting calculations below.

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION									
RPP / Non-RPP:	RPP									
Consumption	2,386	kWh								
Demand	-	kW								
Current Loss Factor	1.0687									
Proposed/Approved Loss Factor	1.0673									
	Current OEB Approved			Proposed			Impact			
	Rate	Volume	Charge	Rate	Volume	Charge				
	($)		($)	($)		($)	$ Change	% Change	Yearly Increase	Yearly Increase for 4 schools
Monthly Service Charge	$ 25.22	1	$ 25.22	$ 32.22	1	$ 32.22	$ 7.00	27.76%	$ 84.00	$ 336.00
Distribution Volumetric Rate	$ 0.0207	2386	$ 49.39	$ 0.0264	2,386	$ 62.99	$ 13.60	27.54%	$ 163.20	$ 652.81
Fixed Rate Riders	$ 2.48	1	$ 2.48		1	$ -	$ (2.48)	-100.00%	-$ 29.76	-$ 119.04
ICM - Fixed	$ -	1	$ -	$ -	1	$ -	$ -			
Volumetric Rate Riders	$ 0.0020	2386	$ 4.77	-$ 0.0018	2386	$ (4.29)	$ (9.07)	-190.00%		
Sub-Total A (excluding pass through)			**$ 81.86**			**$ 90.92**	**$ 9.05**	**11.06%**	$ 217.44	$ 869.77

Customer Class:	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION									
RPP / Non-RPP:	Non-RPP (Other)									
Consumption	44,361	kWh								
Demand	115	kW								
Current Loss Factor	1.0687									
Proposed/Approved Loss Factor	1.0673									
	Current OEB Approved			Proposed			Impact			
	Rate	Volume	Charge	Rate	Volume	Charge				
	($)		($)	($)		($)	$ Change	% Change	Yearly Increase	Yearly Increase for 4 schools
Monthly Service Charge	$ 196.43	1	$ 196.43	$ 229.37	1	$ 229.37	$ 32.94	16.77%	$ 395.28	$ 1,581.12
Distribution Volumetric Rate	$ 3.7949	115	$ 436.41	$ 4.4011	115	$ 506.13	$ 69.71	15.97%	$ 836.56	$ 3,346.22
Fixed Rate Riders	$ 19.34	1	$ 19.34		1	$ -	$ (19.34)	-100.00%	-$ 232.08	-$ 928.32
ICM - Fixed	$ -	1	$ -	$ -	1	$ -	$ -			
Volumetric Rate Riders	$ 0.3736	115	$ 42.96	-$ 0.3340	115	$ (38.41)	$ (81.37)	-189.40%		
Sub-Total A (excluding pass through)			**$ 695.15**			**$ 697.09**	**$ 1.94**	**0.28%**	$ 999.76	$ 3,999.02

c) Please see response to CCC-8.

Vulnerable Energy Consumers Coalition (VECC) Interrogatories

VECC-1

Reference: Exhibit 1, page 11

Preamble: N/A

Question:

a) Please confirm (or correct) that no COVID-19 related costs (OM&A or capital) have been forecast for the test year of this application.

Response:

a) There have been no COVID-19 related costs forecasted for the test year in this application. ERHDC is awaiting the OEB's final determination with regards to treatment of the COVID-19 related DVAs.

VECC-2

Reference: Exhibit 1, page 22

Preamble: N/A

Question:

a) Please confirm that ERHDC's Conditions of Service have been updated to include all of the Board's updated directions since 2012.

Response: -

a) ERHDC's Conditions of Service has not been changed since the last Cost of Service Application.

However, as outlined in Section 1.2 of the Conditions of Service, in the event of a conflict between the terms of the Conditions of Service and the following legislation, regulation and documents

A. Electricity Act, 1998

B. Ontario Energy Board Act, 1998

C. Distribution License

D. Affiliate Relationships Code

E. Transmission System Code

F. Distribution System Code

G. Retail Settlement Code

H. Standard Supply Service Code

I. Environmental Protection Act

the provision of the legislation, distribution license, and regulatory codes shall prevail in the order of priority listed above.

VECC-3

Reference: Exhibit 1, pages 46, 53

Preamble:

***Billing Problems** – In 2019, 12% of customer respondents had a billing problem in the past 12 months, compared to 20% in 2017 and 17% in 2015. This reflects positive changes in customer service. 90% stated ERHDC provides accurate billing.*

Question:

a) While ERHDC has been able to reduce its billing problems they remain comparatively high. Please explain the most common errors encountered and what steps the Utility is taking to address these problems.

b) EHRDC's telephone response time remains significantly below Ontario industry and OEB standards. How is the "fully trained team" different from what existed in the past? Why is the target for calls answered (65% shown in Table 1-23) set below the industry standard of 90%?

Response:

a) Below are ERHDC's billing accuracy statistics by year:

2015	2016	2017	2018	2019
99.93%	99.95%	99.95%	99.89%	99.98%

As demonstrated in the statistics above almost 100% of bills issued to ERHDC customers are accurate. The reported billing problems by customers primarily relate to "high bill" concerns and/or complaints around approved rates and charges reflected on the bill. ERHDC works with customers to explain billing calculations and offers flexible payment plan options.

b) The Industry Target is 65% for Telephone Calls Answered on time and ERHDC has set this as its target.

In 2019, ERHDC's Customer Care Department had staff turnover which resulted in new staff having longer average talk times with customers. The extra time on the phone with customers then led to calls waiting in the queue. The new staff have now been fully trained and are able to handle the calls at the same capacity as the staff who have left.

VECC-4

Reference: Exhibit 2

Preamble: N/A

Question:

a) Please explain why ERHDC is unable to provide the actual gross capital spending amounts for the years 2012 through 2016.

b) Please describe what asset records were kept for this period.

c) In 2014 and 2015 ERHDC made returns on equity far in excess of Board approved amounts. In 2014 ERHDC spent significantly less on capital assets than in prior years. What evidence is ERDHC providing to show that these extraordinary returns were not made by deferring necessary capital spending and harvesting asset values?

Response:

a) Prior to preparing this Cost of Service Application, ERHDC proposed several adjustments to the OEB's Chapter 2 Filing Requirements applicable to this Application, one of which was to limit all variance analysis obligations for the Application to only the test year, the bridge year and no more than the last three actual historical years. Therefore information related to capital spending for the years 2012 through 2016 was not provided at the time of filing.

ERHDC has provided the capital spending amounts for the years 2012 through 2016 in Chapter 2 Appendix 2-BA in the Chapter 2 Appendices filed with these IR responses.

b) The costs associated with the capital expenditures were recorded in the general ledger and a manual summary of the expenditures by job maintained in an excel spreadsheet.

c) While ERHDC's return on equity was high for 2014 and 2015, this was due to rate riders for the recovery of residual historical smart meter costs, recovery of stranded meters, recovery of LRAM and recovery of forgone revenue that were due to expire in April of 2016.

The deferring of capital expenditures would not materially affect the level of the returns on equity. In addition, 2014 is the only year from 2012 to 2021 with gross capital expenditures under $400,000 so there is not a pattern of low capital expenditures.

VECC-5

Reference: Exhibit 4, Appendix 4-A, Schedule C, page 3

Preamble: N/A.

Question:

a) The Proposed Services of PUC Services include the term: "*5. Preparation of annual capital and OM&A budgets including a five-year forecast*." When was the last 5-year capital and OM&A forecast produced for ERHDC?

Response:

a) A 5-year forecast has not formally been prepared in past years. This is because annual capital and OM&A budgeting process includes discussion and review of the Asset Plan for future projects and capital spend. ERHDC's capital and OM&A have been consistent to align to its last cost of service rebasing. OM&A increases have been inflationary and capital plans have been based on priority.

VECC-6

Reference: Exhibit 2, page 20 & Appendix 2-BA

Preamble: N/A

Question:

a) What was the salvage value of the transportation equipment disposed of in 2019?

Response:

a) The transportation equipment disposed of in 2019 was not worth any value.

VECC-7

Reference: Exhibit 2, Appendix 2-BA

Preamble: N/A

Question:

a) Please explain the meaning of the "Adjustment" columns of assets additions in the 2013 ($117,931) and 2015 ($259,198) continuity schedules.

Response:

a) In 2013 the $117,931 was for IFRS adjustments and in 2015 the $259,198 was from the ICM application which was accidentally placed into fixed asset accounts and then adjusted to move to 1508 accounts.

VECC-8

Reference: Exhibit 2, page 22, 43-44 & Appendix 2-BA

Preamble: N/A

Question:

a) ERHDC states that $1,695,956 is being added in 2020 for the ICM projects. Appendix 2-BA under the column entitled "*Adjustment Sub 4 ICM*" it shows an amount of $259,198 for a total of $1,955,154. Please reconcile this with the ICM actual cost of $1,967,931.

b) Please provide the amount of depreciation taken on the ICM assets for each year 2014 through 2020 for these assets and confirm.

c) Please confirm (or correct) that a full year's depreciation was taken in 2014, the year the ICM assets went into service.

Response:

a) The reference on page 22 of Exhibit 2 includes actual capital expenditures in Account 1820 of $5,920 (addition column in 2-BA) plus the inclusion of the Sub 4 ICM amount of $1,690,036 (Adjustment Sub 4 ICM column).

2020 Actual Additions	$5,920
Sub 4 ICM	$1,690,036
Total Acct 1820 additions	$1,695,956

The actual land purchase of $18,696, although part of the project costs, was recorded in fixed assets not the 1508 regulatory account – as such it has been included in the revised revenue requirement calculation but not in the requested transfer to fixed assets from Account 1508. (Exhibit 2, p. 25)

Appendix 2-BA	Adjustment Sub 4 ICM
Distribution Station Equipment <50 kV (1820)	$1,690,036
Poles, Towers & Fixtures (1830)	$259,198
	$1,949,234

Exhibit 2 Table 2-21	Actual Cost
Land	$18,696
Building & Equipment	$1,690,036
Line	$259,198
	$1,967,930

Difference	$18,696

b) The amount of depreciation taken on the ICM assets for each year 2014 through 2020 is presented in the following Table VECC-8.

Table VECC-8 – Sub-4 ICM Depreciation

2014	2015	2016	2017	2018	2019	Total 2014 to 2019	Included in 2020 Deprec	Total 2014 to 2020
$32,422	$50,511	$39,391	$39,391	$39,396	$39,396	$240,507	$39,391	$279,898

c) A full year's depreciation has been taken for 2014.

	Depreciation rate	Actual Cost	Calculated Depreciation
Municipal Substation	2.0%	$1,690,036	$33,801
44 kV line Build	2.5%	$259,198	$6,480
			$40,281
		7 years depreciation	$281,965
		Total Depreciation in Application	$279,898
		Variance	-$2,067

VECC-9

Reference: Exhibit 2, page 49 & Appendix 2-B DSP page 21 Table 2-9

Preamble: N/A

Question:

a) Please provide the 2020 SAIDI/SIAFI reliability statistics for Appendix 2-G.

b) Please update Table 2-9 and 2-10 (Outage by Cause Code) to include the year 2020.

Response:

a) 2020 SAIDI/SAIFI reliability statistics are provided below in Table VECC-9-1 and in Appendix 2-G in the Chapter 2 Appendices filed with these IR responses:

Table VECC-9-1 – 2020 SAIDI/SAIFI Reliability Statistics

Index	Excluding outages caused by loss of supply					
	2015	2016	2017	2018	2019	2020
SAIDI	0.280	2.130	0.350	0.160	0.350	0.210
SAIFI	0.030	1.890	0.100	0.060	0.170	0.060

Index	Including outages caused by loss of supply					
	2015	2016	2017	2018	2019	2020
SAIDI	0.900	10.430	9.480	0.280	0.540	1.580
SAIFI	0.180	4.620	4.790	0.070	0.260	0.380

Index	Excluding Major Event Days					
	2015	2016	2017	2018	2019	2020
SAIDI	0.280	0.550	0.350	0.160	0.350	0.210
SAIFI	0.030	1.100	0.100	0.060	0.170	0.060

b) Table 2-9 and 2-10 of the DSP have been reproduced and updated to include 2020 below as Table VECC-9-2 and Table VECC-9-3:

Table VECC-9-2

Table 2-9: Number of Outages by Cause Codes (2015-2020) – Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	2020	Total Outages	Percent Share
0-Unknown/Other	0	2	0	1	1	0	4	2%
1-Scheduled Outage	0	8	4	7	15	11	45	27%
2-Loss of Supply	1	3	10	1	2	5	22	13%
3-Tree Contacts	2	4	3	2	5	0	16	10%
4-Lightning	0	0	0	0	2	0	2	1%
5-Defective Equipment	4	10	3	5	10	7	39	24%
6-Adverse Weather	4	6	0	1	0	0	11	7%
7-Adverse Environment	0	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0	0%
9-Foreign Interference	2	7	1	4	5	6	25	15%

Table VECC-9-3

Table 2-10: Customers Interrupted by Cause Codes (2015-2020) – Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	2020	Total Outages	Percent Share
0-Unknown/Other	0	7	0	81	81	0	169	1%
1-Scheduled Outage	39	64	29	60	78	94	364	2%
2-Loss of Supply	500	5686	5541	13	320	1063	13123	72%
3-Tree Contacts	2	88	181	2	31	0	304	2%
4-Lightning	0	0	0	0	2	0	2	0%
5-Defective Equipment	41	2941	51	20	159	66	3278	18%
6-Adverse Weather	5	423	0	15	0	0	443	2%
7-Adverse Environment	0	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0	0%
9-Foreign Interference	12	93	79	30	195	46	455	3%

VECC-10

Reference: Exhibit 2, DSP, pages 21-23

Preamble: N/A.

Question:

a) Outages and hours of interruption by defective equipment are among the largest sources of outages. What are the most common equipment failures causing outages and how does the 2021 capital plan address these factors?

Response:

(a) Table VECC-10 below summarizes the number of historical customer interruptions per asset class, and their respective contributions to SAIDI and SAIFI.

Table VECC-10 – Outage Statistics by Asset Class

Asset Class	Customers Interrupted	*Total Customer Hours of Interuption*	*SAIDI*	*SAIFI*
Transformers	36	122.5	0.037164	0.010912
Services (wires, connectors)	117	124.25	0.037493	0.035295
Switches	32	79.75	0.023983	0.009638
U/G Primary Cable	288	720	*0.2152*	*0.0861*
Insulators	2593	43.2	*0.0129*	*0.7757*

Projects in the 2021 capital plan that address common outage causes include:

- Overhead cutout renewal (replacement of porcelain switches and insulators - a common failure point)
- MS3 cable replacement (replacement of aging underground cable)

- Overhead transformer renewal

VECC-11

Reference: Exhibit 2, DSP, page 23

Preamble: N/A

Question:

a) Customer hours interrupted due to scheduled outages has increased since 2016. Please explain what steps are being taken by ERHDC to minimize interruption time during scheduled outages.

b) Please describe how customers are informed about scheduled outages.

Response:

a) Written job plans are prepared ahead time to ensure efficiency, and any work able to be completed to support a shorter outage duration is completed in advance. ERHDC also takes advantage of Hydro One scheduled interruptions by co-ordinating any work that can be scheduled during the same timeframe.

b) For smaller outages (e.g.: single transformer replacement), staff will visit door to door and deliver outage notices to the customers. For larger outages (an entire neighborhood or the entire community), ERHDC uses automated calls, bill inserts, and radio ads to inform customers of upcoming outages.

VECC-12

Reference: Exhibit 2, DSP, page 39-

Preamble: N/A.

Question:

a) For each asset type listed in Table 3-3 please indicate how asset condition was determined, specifically: historical records asset age/ non-intrusive observation/sample physical testing/entire population tested.

b) Please confirm (or correct) that no new asset condition assessment has occurred since "*the second quarter of 2015*."

Response:

a) Table 3-3 has been reproduced as follows as Table VECC-12 with an additional column to indicate the methods used and factors considered in evaluating asset condition.

Table VECC-12 – Updated Table 3-3 with Methods and Factors for Asset Condition

<table>
<tr><th>Asset Type</th><th>Count</th><th>Methods/Factors for Asset Condition Assessment</th></tr>
<tr><td>Overhead lines 3 phase 44 kV (km)</td><td>5.8</td><td rowspan="8">Methods:
Visual inspection during 1/3 plant inspection
Annual IR scanning
Routine patrolling
Factors:
Age</td></tr>
<tr><td>Overhead lines 3 phase 12.47 kV (km)</td><td>9.4</td></tr>
<tr><td>Overhead lines 3 phase 4.16 kV (km)</td><td>21.7</td></tr>
<tr><td>Overhead lines 2 phase 12.47 kV (km)</td><td>1.1</td></tr>
<tr><td>Overhead lines 2 phase 4.16 kV (km)</td><td>1</td></tr>
<tr><td>Overhead lines 1 phase 7.2 kV (km)</td><td>35.24</td></tr>
<tr><td>Overhead lines 1 phase 2.4 kV (km)</td><td>16</td></tr>
<tr><td>Total of Overhead Lines (km)</td><td>90.24</td></tr>
<tr><td>Distribution line poles owned by ERH</td><td>1,307</td><td rowspan="3">Methods:
Non-destructive pole testing by pole-testing contractor (resistograph drilling, sounding, visual)
Visual inspection during 1/3 plant inspection and routine patrolling
Factors:
Age</td></tr>
<tr><td>Joint use poles on which distribution lines are attached (owned by Bell)</td><td>685</td></tr>
<tr><td>Total distribution system poles</td><td>1,992</td></tr>
<tr><td>Underground 3 phase cables 4.16 kV (km)</td><td>1.3</td><td rowspan="2">Methods:</td></tr>
<tr><td>Underground 1 phase cables 2.4 kV (km)</td><td>7.6</td></tr>
</table>

Total of Underground Cables (km)	10.6	• Visual inspection during 1/3 plant inspection and routine patrolling **Factors:** • Age
Submarine 1 phase cable 7.2Kv (km)	3.0	
Pole mounted transformer,1-ph	694	**Methods:** • Visual inspection during 1/3 plant inspection • Annual IR scanning • Routine patrolling **Factors:** • Age
1 phase cut-outs	694	
1 phase disconnects	76	
3 phase disconnects	68	
3 phase load break switches	9	
Pad-mount 37.5 kVA, 1-ph	4	
Pad-mount 50 kVA, 3-ph	3	
Pad-mount 75 kVA, 3-ph	1	
Pad-mount 150 kVA, 3-ph	1	
Pad-mount 500 kVA, 3-ph	3	
Transclosures, 1-ph	49	
Revenue Meters	3283	
Substations	4	**Methods:** • Monthly substation visual checks • Annual transformer oil testing • Third-party substation maintenance • IR Scanning **Factors:** • Age

b) No formal Asset Condition Assessment plan has been prepared since 2015 however ongoing asset reviews have been conducted. These include annual non-destructive pole testing, annual one-third plant inspection and field staff inspections performed in the course of other duties. Furthermore, testing of overhead distribution transformer for PCB contamination has been completed for the towns of Massey and Webbwood and is planned for 2021 in the Espanola town centre.

VECC-13

Reference: Exhibit 2, Appendix 2-AA (Capital Projects Table)

Preamble: N/A

Question:

a) If not already, please update Appendix 2-AA to show 2020 actual capital expenditures.

Response:

a) Appendix 2-AA has been updated to show 2020 actual capital expenditures and is filed in live excel form as part of the file named "ERHDC_2021_Filing_Requirements_Chapter2_Appendices_IRR_Response_20210325".

VECC-14

Reference: Exhibit 2, Appendix 2-AA (Capital Projects Table)

Preamble: N/A

Question:

a) Please explain the reason Spanish River Drive underwent significant renewal of plant in 2020.

b) Was the rear-lot replacement in this project "like-for-like" in the same location or was the line relocated?

c) Was any overhead plant replaced by underground plant for this project?

d) Did the Espanola Golf and Country Club provide any contribution-in-aid of construction for this project? If not please explain why not.

Response:

a) The Spanish river drive project began in 2020 to relocate a deteriorated section of rear lot single phase 2400V line along an escarpment on the northern side of Spanish River Drive. Escarpment erosion, difficult access, significant line clearing requirements, and deteriorating infrastructure played a role in deciding to relocate the line.

b) The rear lot line has been relocated to municipal property at the front of the lots on the north side of Spanish River Drive/Sheppard Street.

c) The new installations are underground.

d) The Espanola Golf and Country Club did not provide any contribution in-aid of construction for this project. The line relocation does not affect any services related to the Espanola Golf and Country Club.

VECC-15

Reference: Exhibit 3, page 3

Preamble:

The Application states:

"In summary, as a starting point, ERHDC used the same regression analysis methodology approved by the Ontario Energy Board in its 2012 Cost of Service ("COS") application (EB-2011-0319) and updated the analysis for actual power purchases to the end of the 2019. The updated regression analysis included heating and cooling degree days, spring fall flag, and number of days in the month."

The Application also states: "No assumptions including economic assumptions were used."

Question:

a) Does the current Application use the same explanatory variables (i.e., heating and cooling degree days, spring fall flag, and number of days in the month) as the EB-2011-0319 Application?

b) If the explanatory variables are not the same as those used in EB-2011-0319, please explain why.

Response:

a) The current application used one additional variable, number of days in the month, than the EB-2011-0319 Application.

b) The regression model was previously run without the number of days in the month and with the number of days in the month. The result was that by including the number of days in the month, it represented a better regression The Multiple R, R Square and adjusted R square values are all higher when using the explanatory variable of number of days in the month.

VECC-16

Reference: Exhibit 3, pages 5-6 Load Forecast Model, Rate Class Energy Model Tab, Appendix 2-IA

Preamble:

The Application states (page 5): "In the above Table 3-2, the billed GWh data from 2010 to 2019 reflects actual weather and weather normal conditions in each year."

The Application also states (page 5): "On a rate class basis, the actual and forecasted billed amounts are shown in Table 3-3. Actual volumes have been weather normalized by rate class using the weather normal conversion factor from Table 3-7."

Question:

a) Table 3-2 only contains one column with GWh values. Are the values in this column the weather normalized values per the title of Table 3-2?

b) Are the GWh values in Table 3-3 also weather normalized (Note: The totals match those in Table 3-2)?

c) The historical consumption values in the Rate Class Energy Model Tab are presented as (actual) metered values. However, the values are the same as those in Tables 3-2 and 3-3 which are presented as weather normalized. Please reconcile.

d) Neither the weather normalized or actual values in Appendix 2-IA match the values in Tables 3-2 or 3-3. Please reconcile.

Response:

a) The values for 2010 through 2019 are weather actual numbers and the 2020 bridge year and 2021 test year are weather normalized projections.

b) In Table 3-3, it breaks down the information in Table 3-2 into specific customer classes. Therefore, the values for 2010 through 2019 are weather actual numbers and the 2020 bridge year and 2021 test year are weather normalized projections.

c) As indicated in the above two responses, the numbers in Table 3-2 and Table 3-3 are actual numbers for 2010 through 2019.

d) Table VECC-16 has been provided below to show that the numbers in Appendix 2-IA do in fact reconcile to Table 3-2 of the load forecast model. As an example, this table shows the residential class only but the same methodology can be compared for all classes. The year 2015 through 2019 show weather actual consumption and the 2020 bridge year and 2021 test year shows weather normalized projections.

Table VECC-16 – Reconciliation of Appendix 2-IA and Table 3-2

Customer Class:	Residential									
	Calendar Year (for 2021 Cost of Service	Customers			Consumption (kWh) (3)				Table 3-2	
						Actual (Weather actual)	Weather-normalized	Weather-normalized		
Historical	*2015*	0	2,856		Actual	30,963,982.24	30,756,422.63		Actual	30.96398
Historical	*2016*	0	2,861		Actual	29,475,507.11	29,586,088.58		Actual	29.47551
Historical	*2017*	0	2,872		Actual	28,877,055.71	29,168,637.01		Actual	28.87706
Historical	*2018*	0	2,888		Actual	31,054,130.41	30,521,740.48		Actual	31.05413
Historical	*2019*	0	2,901		Actual	31,777,563.04	31,771,729.87		Actual	31.77756
Bridge Year	*2020*	0	2,905		Forecast		32,702,467.45		Weather Normal	32.70247
Test Year	*2021*	0	2,910		Forecast		32,639,691.74		Weather Normal	32.63969

VECC-17

Reference: Exhibit 3, page 5

Preamble:

The Application states:

"Customer/Connection values are on an average basis and street lights and sentinel lights are measured as connections. The historical connection values for street lights have been measured as devices. For the 2020 Bridge Year and 2021 Test Year Street Lights have been updated from number of devices to number of connections."

Question:

a) Please indicate how the historical average customer/connection counts for each class are determined (e.g., are they the average of the 12 monthly values for the class?).

b) Please provide the 2020 customer/connection counts for each class as of June 30, 2020 and December 31, 2020.

c) What is the basis for the Street Lights update from number of devices to number of connections (e.g., what analysis was undertaken and for what point in time)?

Response:

a) Historical average customers/connection counts for each class are determined using the year end December 31 values.

b) The June 30, 2020 and December 31, 2020 customer/connections counts are presented in Table VECC-17 below.

Table VECC-17 – Customer Connection Counts for June 30, 2020 and December 31, 2020

Rate Class	June 30, 2020	December 31, 2020
Residential	2904	2918
GS<50	381	381
GS>50	29	29
Street	1072	1072
USL	21	21
Sentinel	24	24

c) ERHDC has referred to the guidance in the OEB's Report of the Board on Review of the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383) issued December 19, 2013, which amended section 2.4.6 of the DSC, and the OEB's letter of June 12, 2015 re: Issuance of New Cost Allocation Policy for Street Lighting Rate Class, which outlined a new cost allocation policy for the street lighting rate class ("OEB Guidance").

Following the OEB Guidance and the methodology set out therein, ERHDC updated its customer count for Street Lights from number of devices to number of connections.

VECC-18

Reference: Exhibit 3, pages 3 & 9

Preamble: At page 3 the Application states: "The updated regression analysis included heating and cooling degree days, spring fall flag, and number of days in the month."

At page 9 the Application states: "The regression analysis also indicates that the number of customers are significant contributors to the total energy used in the ERHDC service area."

Question:

a) Please reconcile the statement on page 9 with the fact that the regression model used does not include number of customers as an explanatory variable.

b) Please provide an alternative load forecast where the number of customers is included as an explanatory variable.

Response:

a) The regression model used does not include number of customers as an explanatory variable. The statement made at page 9 was included in error and should state:

"The multivariate regression model has determined drivers of year-over-year changes in ERHDC's load growth are weather (heating and cooling degree days), and calendar variables (days in month and seasonal flag)."

b) ERHDC does not record the monthly number of customers in order to add this as an explanatory variable. Therefore, the data is not readily available.

VECC-19

Reference: Exhibit 3, page 10

Preamble:

The Application states:

"The 2020 and 2021 weather normal purchases have been adjusted to include the impact of reduced consumption from the installation of new street lights. On a billed energy basis the average historical annual kWh for street lights from 2010 to 2013, of 616,182 kWh has been reduced to 224,919 kWh for 2020 and 2021 to reflect the consumption of the new energy efficient street lights installed during 2014 in the Town of Espanola and most recently August 2020 for the Township of Sables-Spanish River."

Question:

a) How was the 222,919 kWh value for 2020 established?

b) Over what period of time were street light conversions in the Township of Sables-Spanish made?

Response:

a) There is a tab in the Load Forecast titled "Street Light Adjustment" that shows a table of how the calculation was achieved. This table has been reproduced below as Table VECC-19.

Table VECC-19 – Street Light Adjustment

	Total	Res	GS<50	GS>50	Sentinel	Street	USL
New	58,793,724	32,706,054	10,211,911	15,511,400	24,258	224,919	115,182
Old	58,793,724	32,639,692	10,191,190	15,482,365	24,258	341,037	115,182
Difference		66,362	20,721	29,035		- 116,118	
USED	58,677,605	32,639,692	10,191,190	15,482,365	24,258	224,919	115,182

The highlighted numbers were used in the final product of the load forecast. A manual adjustment was made to ensure that the regression model was not incorrectly allocating the reduced consumption from the Street Light class to the other classes. For example, it was allocating 116,118 kWh to the other classes which would be incorrect. Therefore, for all classes other than Street Lights, the OLD row was used for the final regression output.

b) Streetlight LED conversions were completed between July 28, 2020 and September 1, 2020 in the Township of Sables-Spanish.

VECC-20

Reference: Exhibit 3, page 27 Appendix 2-H

Preamble:

At page 27 the Application states: "ERHDC was previously charging the Town of Espanola $18,136 for water billing collection. This is no longer included in revenue, as ERHDC is no longer performing these services for the Town of Espanola."

Question:

a) In what USOA account were the revenues received from the Town of Espanola recorded?

b) Were there any reductions in OM&A costs as a result of ceasing to provide these services? If not, why not? If yes, where in Exhibit 4 are these reductions evident?

c) With respect to Accounts 4375 and 4380 please explain: i) why there are continuing revenues and expenses relate to CDM in 2020 and 2021 and ii) what the revenues and costs attributed to ATF were?

d) Please provide the derivation of the $85,356 in 2021 for pole attachment revenues.

Response:

a) The revenue for water billing collection were recorded in Account 4235.

b) No. There was no decrease in service agreement costs from PUC Services when the water billing ended as the difference in costs for bill processing, mailing, etc. was not materially different. (i.e. water was billed as a monthly fixed charge as a single line item added onto the balance of the distribution bill – the deletion of this one line item did not significantly impact costs)

c) Revenue and Expenses related to CDM continue to accrue due to programs still running and a backlog of submissions.

The amount of revenues and expenses from ATF was $342,968 in 2020.

d) ERHDC was able to verify the exact number of pole connections for 2020 and thus update the amount in this account. ERHDC has 1801 connections as of December 31, 2020. At a rate of $44.50 this would equate to $80,145 in pole attachment revenues. ERHDC has adjusted this within the Revenue Requirement Workform and Chapter 2 Appendices that are filed with these IR responses.

VECC-21

Reference: Exhibit 4, page 13

Preamble: N/A

Question:

a) Please update Appendix 2-JA and Appendix 2-JC (OM&A Programs) to include 2020 actual results (if not already).

Response:

a) Below is Appendix 2-JA and Appendix 2-JC updated to included 2020 actual results.

Summary of Recoverable OM&A Expenses

	2012 Last Rebasing Year OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 249,346	$ 300,622	$ 374,022	$ 428,161	$ 400,779	$ 401,109
Maintenance	$ 397,158	$ 285,287	$ 267,091	$ 291,771	$ 315,632	$ 333,727
SubTotal	**$ 646,504**	**$ 585,908**	**$ 641,113**	**$ 719,932**	**$ 716,411**	**$ 734,837**
%Change (year over year)			9.4%	12.3%	-0.5%	2.6%
%Change (Test Year vs Last Rebasing Year - Actual)						9.7%
Billing and Collecting	$ 371,722	$ 436,238	$ 429,999	$ 452,917	$ 418,182	$ 428,448
Community Relations	$ 1,000	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 338,898	$ 377,398	$ 339,127	$ 496,779	$ 388,854	$ 490,146
SubTotal	**$ 711,620**	**$ 813,636**	**$ 769,127**	**$ 949,696**	**$ 807,036**	**$ 918,594**
%Change (year over year)			-5.5%	23.5%	-15.0%	13.8%
%Change (Test Year vs Last Rebasing Year - Actual)						46.3%
Total	**$ 1,358,124**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,523,447**	**$ 1,653,431**
%Change (year over year)		1.1%	0.8%	18.4%	-8.8%	8.5%

	2012 Last Rebasing Year OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Operations	$ 249,346	$ 300,622	$ 374,022	$ 428,161	$ 400,779	$ 401,109
Maintenance	$ 397,158	$ 285,287	$ 267,091	$ 291,771	$ 315,632	$ 333,727
Billing and Collecting	$ 371,722	$ 436,238	$ 429,999	$ 452,917	$ 418,182	$ 428,448
Community Relations	$ 1,000	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 338,898	$ 377,398	$ 339,127	$ 496,779	$ 388,854	$ 490,146
Total	**$ 1,358,124**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,523,447**	**$ 1,653,431**
%Change (year over year)		1.1%	0.8%	18.4%	-8.8%	8.5%

	Last Rebasing Year 2012 OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	Variance 2020 Bridge vs. 2019 Actuals	2021 Test Year	Variance 2021 Test vs. 2020 Bridge
Operations	**$ 249,346**	**$ 300,622**	**$ 374,022**	**$ 428,161**	**$ 400,779**	**-$ 27,383**	**$ 401,109**	**$ 331**
Maintenance	**$ 397,158**	**$ 285,287**	**$ 267,091**	**$ 291,771**	**$ 315,632**	**$ 23,861**	**$ 333,727**	**$ 18,095**
Billing and Collecting	**$ 371,722**	**$ 436,238**	**$ 429,999**	**$ 452,917**	**$ 418,182**	**-$ 34,734**	**$ 428,448**	**$ 10,266**
Community Relations	**$ 1,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Administrative and General	**$ 338,898**	**$ 377,398**	**$ 339,127**	**$ 496,779**	**$ 388,854**	**-$ 107,925**	**$ 490,146**	**$ 101,292**
Total OM&A Expenses	**$ 1,358,124**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,523,447**	**-$ 146,181**	**$ 1,653,431**	**$ 129,984**
Adjustments for Total non-recoverable items[3]								
Total Recoverable OM&A Expenses	**$ 1,358,124**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,523,447**	**-$ 146,181**	**$ 1,653,431**	**$ 129,984**
Variance from previous year		$ 662,311	$ 10,696	$ 259,388	-$ 146,181		$ 129,984	
Percent change (year over year)			1%	18%	-9%		9%	
Percent Change: Test year vs. Most Current Actual							-0.97%	
Simple average of % variance for all years							-2.07%	
Compound Annual Growth Rate for all years								2.7%
Compound Growth Rate (2019 vs. 2012 Actuals)							3.7%	

VECC-22

Reference: Exhibit 4, page 23

Preamble: N/A

Question:

a) What was the incremental in pole rentals costs in 2019?

Response:

a) The incremental pole rental costs were $6,759 in 2019.

VECC-23

Reference: Exhibit 4, Appendix 2-JC

Preamble: N/A

Question:

a) Property insurance costs and injuries and damage costs have nearly tripled since 2012 (approximately 10k to 28k). Please explain the reasons.

Response:

a) ERHDC did an assessment of its insurance coverages in 2019. It was determined that additional coverage was needed for the substation assets causing the increase to Account 5635. Additionally, more liability insurance coverage and business travel coverage were added which caused the increase to Account 5640. Previous coverage limits were found to be insufficient.

VECC-24

Reference 1: Exhibit 4, Appendix 2-K (Table 4-26)

Preamble: N/A

Question:

a) Of the 7.31 FTEs designated for 2021 how many of these are directly employed by ERHDC and how many are part of the PUC Services contract?

b) What amount of the Service Fees (Schedule B) are included as compensation costs in Appendix 2-K for each year shown?

Response:

a) All 7.31 FTE's are employed by ERHDC.

b) There are no service fees included as compensation in Appendix 2-K.

VECC-25

Reference 1: Exhibit 4, page 13, Appendix 2-JC

SCHEDULE 'B' – FEES

Price Table

Price (*)	Year 1	Year 2	Year 3	Year 4	Year 5
Management Services	$156,141.32	$160,044.86	$164,045.98	$167,326.90	$170,673.44
Customer Services	$5.26/ meter/month	$5.39/ meter/month	$5.53/ meter/month	$5.64/ meter/month	$5.75/ meter/month
IT Server Hosting Services	$7,500.00	$7,687.50	$7,879.69	$8,037.28	$8,198.03

Please Note: (*) Applicable taxes not included.

	June 1 2016: 2.75%	June 1 2017: 2.50%	June 1 2018: 2.50%	June 1 2019: 2.0%	June 1 2020: 2.0%

Preamble: N/A

Question:

a) Please show where in Appendix 2-JC (OM&A Programs Table) the amounts charged under Schedule B of the PUC Services contract are found.

Response:

Please refer to OEB Staff-28 and the following Table VECC-25, which shows which accounts the amounts charged under Schedule B of the PUC services contract can be found:

Table VECC-25 – Accounts with Amounts Charged Under Schedule B of PUC Services Contract

Account	2017	2018	2019	2020	2021
5005 Operations Supervisor	$63,315.35	$55,678.99	$62,381.28	$68,882.97	$65,290.93
5025 O/H Lines Expense	$0.00	$0.00	$5,455.40	$0.00	
5045 U/G Lines Expense	$1,071.91	$0.00	$0.00	$0.00	
5105 Maint Supervision	$60,660.94	$52,698.16	$59,062.07	$65,257.53	$61,854.56
5315 Customer Billing	$162,727.88	$142,547.76	$159,048.13	$193,871.01	$154,690.95
5320 Collecting	$78,724.95	$67,762.53	$75,610.44	$90,638.28	$79,595.11
5615 General Admin	$0.00	$0.00	$0.00	$8,638.50	
5620 Office Expenses	$0.00	$0.00	$164.50	$16,016.26	
5630 Outside Services	$47,779.22	$44,508.54	$44,516.52	$47,130.47	$44,672.74
	$414,280.25	$363,195.98	$406,238.34	$490,435.02	$406,104.30

VECC-26

Reference: Exhibit 4, pages 39-

Table 4 - 31 Regulatory Costs

Service	$	Expense Included in Test Year
Legal and rates consulting expenses to complete the application	$100,000	$20,000
Consultant - completion of application, interrogatories, settlement conference, draft settlement and final order	$282,539	$56,508
Services related to the Distribution System Plan and Asset Management Plan	$65,000	$13,000
Legal and rates consulting expenses for the settlement conference	$50,000	$10,000
Intervenor expenses	$50,000	$10,000
OEB Costs	$20,000	$4,000
Settlement conference expenses	$5,000	$1,000
LRAM consulting services	$10,000	$2,000
	$582,539	$116,508

Preamble: N/A

Question:

a) Please provide the actual Board assessment cost for ERHDC for 2020.

b) Please show the actual application costs (by category) incurred to date for Table 4-31.

Response:

a) The Board assessment cost for 2020 is $13,840.

b) Table 4-31 has been updated to show application costs as of December 31, 2020 as seen in Table VECC-26 below.

Table VECC-26 – Updated Table 4-31 Showing Application Costs as of December 31, 2020

Service	Projection	Expenses Included in Test Year	As of December 31, 2020
Legal and rates consulting expenses to complete the application	$100,000	$20,000	$104,215
Consultant - completion of application, interrogatories, settlement conference, draft settlement and final order	$282,539	$56,508	$288,012
Service related to the DSP and AMP	$65,000	$13,000	$56,250
Legal and rates consulting expenses for the settlement conference	$50,000	$10,000	$0
Intervenor Expenses	$50,000	$10,000	$0
OEB Costs	$20,000	$4,000	$0
Settlement Conference Expenses	$5,000	$1,000	$0
LRAM consulting services.	$10,000	$2,000	$10,800
	$582,539	$116,508	$459,278

VECC-27

Reference: Exhibit 4, page 42

Preamble: N/A

Question:

a) Please clarify – is ERHDC proposing to include $2,000 for LEAP or .12% of the service revenue requirement (in the filing $2,727)?

Response:

a) ERHDC is proposing .12% of the service revenue requirement once it is finalized.

VECC-28

Reference: Exhibit 4, pages 77-78
Appendix 4-K
LRAMVA Workform

Preamble: N/A

Question:

a) Based on the values used in the LRAMVA Workform please provide a summary of the historic CDM savings from 2011-2019 programs (total for all customer classes) in the following format:

Impact of Historical Annualized CDM (kWh)					
Calendar Year/ CDM Program Year	2011	Columns for Each Subsequent Year up to 2020			2021
2011 CDM Program Impacts					
Actual CDM impacts for each year to 2018 – one row per year					
2019 CDM Programs Impacts					
Total					

Response:

a) Please see the following Table VECC-28 for the historic CDM savings from 2011-2019.

Table VECC-28 – Historic CDM Savings from 2011 to 2019

Year program offered	Impact of Historical Annualized CDM (kWh/a)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2011	367,205	367,205	367,205	366,737	361,516	352,135	343,666	343,546	350,453	328,956	321,744
2012		401,270	401,270	401,270	298,193	284,895	62,497	56,493	55,849	55,849	46,491
2013			162,869	162,747	160,096	150,460	114,731	107,476	107,476	107,243	100,930
2014				427,702	427,617	416,210	383,474	377,772	373,282	366,650	366,547
2015					519,241	517,001	516,917	516,833	515,306	514,899	514,898
2016						373,465	373,465	373,465	373,465	373,465	373,465
2017							1,283,580	1,147,415	1,147,415	1,146,944	1,146,944
2018								340,741	339,846	338,950	338,950
2019									630	630	630
2020										0	0
Total	**367,205**	**768,475**	**931,344**	**1,358,456**	**1,766,663**	**2,094,166**	**3,078,329**	**3,263,741**	**3,263,722**	**3,233,587**	**3,210,600**

VECC-29

Reference: Exhibit 5

Preamble: N/A

Question:

a) Please confirm (or correct) that ERHDC has long-term loans in amounts in excess of the entire 2021 regulated rate base of the Utility (i.e., $11,456,520 as compared to $7,599,049).

b) In addition to interest expenses are any amounts of principle due on any of the long-term loans in 2021?

Response:

a) The Chapter 2 Appendices, Appendix-OB has been updated to reflect the most recent debt. The live excel version of the Chapter 2 Appendices has been submitted with these IR responses. ERHDC has $12,174,693 in long term loans.

b) Please see the following Table VECC-29 for the principal due on the loans for the year.

Table VECC-29 – Principal Due on Loans

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Principal Due in 2021
1	Promissory Note	TD Loan	Third-Party	Fixed	1-Oct-19	25	$ 7,789,530.00	2.93%	$ 228,077	$0
2	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	28-Sep-18	No Term	$ 200,000.00	2.45%	$ 4,900	$0
3	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	13-Apr-20	No Term	$ 265,000.00	2.45%	$ 6,493	$0
4	Grid Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	1-Jan-21	No Term	$ 572,000.00	2.45%	$ 14,014	$0
5	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	2021	No Term	$ 230,000.00	2.45%	$ 5,635	$0
6	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	10	$ 160,210.00	2.73%	$ 4,374	$30,318
7	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	25	$ 1,822,030.00	3.78%	$ 68,873	$62,169
8	Promissory Note	TD Loan	Third-Party	Fixed Rate	2-Sep-20	30	$ 645,923	1.84%	$ 11,885	$16,463
9	Promissory Note	TD Loan	Third-Party	Fixed Rate	10-Mar-21	30	$ 490,000	2.67%	$ 10,903	$8,919
Total							$ 12,174,693	2.92%	$ 355,153	$117,869

VECC-30

Reference: Exhibit 5

Preamble: N/A

Question:

a) If ERHDC is over leveraged please explain why it is not more appropriate to calculate the long-term debt rate component by taking the lowest cost debt up to the point of notional long-term debt structure of $4,255,467?

b) Please recalculate the long-term debt rate based on the premise in (a), that is, that ERHDC is compensated at only for the lowest cost embedded up to an amount of $4,255,467.

Response:

a) ERHDC's leverage position was fully disclosed and considered by the OEB as part of the EB-2019-0015 MAADs Decision with regards to the Phase 1 transaction. At page 13 of the MAADs Decision the OEB notes:

> "*The OEB's rate-setting policies set rates based on a deemed capital structure of 60% debt and 40% equity applied to a rate base. This means that rates are generally set based on a deemed debt level of 60% of rate base regardless of the actual debt of the utility. While there will be an actual incremental interest expense related to the $8 million purchase price loan, rates have already been set based on a deemed debt of 60% of rate base. The Applicant has forecast that actual combined debt for the Applicant and North Bay Hydro will remain below that 60% level.*"

In this context, ERHDC has calculated the long term debt component consistent with the OEB's EB-2009-0084 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2009 as well as the method used and approved in ERHDC's 2012 Cost of Service application.

The approach proposed in this interrogatory would represent a dramatic departure from the OEB's cost of capital policies that systematically underfunds the utility's actual cost of debt, and risk undermining the financial viability of the utility as a whole.

b) The recalculated long-term debt rate has been provided in Table VECC-30 below. See also the response to part (a).

Table VECC-30 – Table Showing Recalculated Long-Term Debt Rate

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Principal Due in 2021
1	Promissory Note	TD Loan	Third-Party	Fixed	1-Oct-19	25	$ 7,789,530.00	2.93%	$ 228,077	$0
2	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	28-Sep-18	No Term	$ 200,000.00	2.45%	$ 4,900	$0
3	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	13-Apr-20	No Term	$ 265,000.00	2.45%	$ 6,493	$0
4	Grid Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	1-Jan-21	No Term	$ 572,000.00	2.45%	$ 14,014	$0
5	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	2021	No Term	$ 230,000.00	2.45%	$ 5,635	$0
6	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	10	$ 160,210.00	2.73%	$ 4,374	$30,318
7	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	25	$ 1,822,030.00	3.78%	$ 68,873	$62,169
8	Promissory Note	TD Loan	Third-Party	Fixed Rate	2-Sep-20	30	$ 645,923	1.84%	$ 11,885	$16,463
9	Promissory Note	TD Loan	Third-Party	Fixed Rate	10-Mar-21	30	$ 490,000	2.67%	$ 10,903	$8,919
Total							$ 12,174,693	2.92%	$ 355,153	$117,869
				Revised Long Term Debt Rate			$4,255,467.00	2.53%	$ 107,754	

VECC-31

Reference: Exhibit 5, Table 5-1, page 4 / Exhibit 6, Table 6-1, page 3

Table 5 - 1: Long Term Debt

Description	Lender	Affiated with LDC?	Principal		Interest Cost
Promissory Note	Infrastructure Ontario	N	$2,100,000	3.78%	$79,380
Promissory Note	Infrastructure Ontario	N	$300,000	2.73%	$8,190
Promissory Note (1)	North Bay Hydro Distribution Limited	Y	$200,000	2.45%	$4,900
Promissory Note (2)	North Bay Hydro Distribution Limited	Y	$265,000	2.45%	$6,493
Promissory Note (3)	North Bay Hydro Distribution Limited	Y	$572,000	2.45%	$14,014
Promissory Note (4)	North Bay Hydro Distribution Limited	Y	$230,000	2.45%	$5,635
Promissory Note	TD Loan	N	$7,789,530	2.928%	$228,077
			$11,456,530		$346,689
			Weighted Debt Cost Rate for 2021		3.03%

Table 6- 1: Revenue Deficiency Calculation

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$449,736
2	Distribution Revenue	$1,621,267	$1,621,267
3	Other Operating Revenue Offsets - net	$201,416	$201,416
4	Total Revenue	$1,822,683	$2,272,419
5	Operating Expenses	$1,884,820	$1,884,820
6	Deemed Interest Expense	$134,095	$134,095
8	Total Cost and Expenses	$2,018,915	$2,018,915
9	Utility Income Before Income Taxes	($196,232)	$253,504
10	Tax Adjustments to Accounting Income per 2013 PILs model	($317,522)	($317,522)
11	Taxable Income	($513,754)	($64,018)
12	Income Tax Rate	0.00%	0.00%
13	Income Tax on Taxable Income	$ -	$ -
14	Income Tax Credits	$ -	$ -
15	Utility Net Income	($196,232)	$253,504
16	Utility Rate Base	$7,599,049	$7,599,049
17	Deemed Equity Portion of Rate Base	$3,039,619	$3,039,619
18	Income/(Equity Portion of Rate Base)	-6.46%	8.34%
19	Target Return - Equity on Rate Base	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-14.80%	0.00%
21	Indicated Rate of Return	-0.82%	5.10%
22	Requested Rate of Return on Rate Base	5.10%	5.10%
23	Deficiency/Sufficiency in Rate of Return	-5.92%	0.00%
24	Target Return on Equity	$253,504	$253,504
25	Revenue Deficiency/(Sufficiency)	$449,736	($0)
26	Gross Revenue Deficiency/(Sufficiency)	$449,736 (1)	

Preamble: N/A

Question:

a) ERHDC has actual long-term debt interest costs of $346,689. Only $134,095 of interest costs, including short term funds, are recovered in rates. The difference, $212,594 is almost the same as the entire return on equity being sought (i.e., $253,504). This would indicate that ERHDC will not be able to achieve its Board approved rate of return on equity and in fact may have a financial loss. Given this please explain how the financial security of the utility is being maintained over the period of the rate plan.

b) Please explain how the long-run financial viability of this Utility is being addressed.

Response:

(a) and (b)

Please make reference to pages 15-18 of the OEB's Decision and Order dated August 22, 2019 in EB-2019-0015 (the MAADs Decision) for a fulsome discussion of the unique circumstances and arrangements that were put in place for ERHDC following the closing of the Phase 1 transaction together with the rationale for, and protections put in place to ensure, the ongoing financial viability of ERHDC.

In that proceeding, and again in this interrogatory response, NBHDL confirms its commitment to, in the event the Phase 2 transaction does not materialize, prudently monitor ERHDC's financial health as a standalone entity and take all necessary steps to ensure the financial viability of ERHDC.

VECC-32

Reference: Exhibit 5, Appendix 2-OB, (Table 5-3)

Table 5 - 3: Debt Instruments

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Espanola	Affiliated	Fixed Rate		No Term	$ 1,185,416	0.0441	$ 52,276.83	
2	Promissory Note	Township of Sable Spanish River	Affiliated	Fixed Rate		No Term	$ 339,095	0.0441	$ 14,954.10	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate		25	$ 2,100,000	0.0378	$ 79,380.00	
4	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate		10	$ 300,000	0.0273	$ 8,190.00	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 3,924,511	3.94%	$ 154,800.92	

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Espanola	Y	Fixed		No Term	$1,185,415.61	0.0441	$ 52,276.83	
2	Promissory Note	Township of Sable Spanish River	Y	Fixed		No Term	$ 339,095.14	0.0441	$ 14,954.10	
3	Promissory Note	Infrastructure Ontario	N	Fixed		25	$2,100,000.00	0.0378	$ 79,380.00	
4	Promissory Note	Infrastructure Ontario	N	Fixed		10	$ 300,000.00	0.0273	$ 8,190.00	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 3,924,511	3.94%	$ 154,800.92	

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	TD Loan	Third-Party	Fixed		25	$7,789,530.00	0.02928	$ 228,077.44	
2	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate		No Term	$ 200,000.00	0.0395	$ 7,900.00	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed		25	$2,100,000.00	0.0378	$ 79,380.00	
4	Promissory Note	Infrastructure Ontario	Third-Party	Fixed		10	$ 300,000.00	0.0273	$ 8,190.00	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 10,389,530	3.11%	$ 323,547.44	

Preamble:

Question:

a) Please amend Appendix 2-OB to show the start dates of all the notes.

Response:

a) Appendix 2-OB has been reproduced below to include Start dates.

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Espanola	Affiliated	Fixed Rate	Pre 2011	No Term	$ 1,185,416	4.41%	$ 52,276.83	
2	Promissory Note	Township of Sable Spanish River	Affiliated	Fixed Rate	Pre 2011	No Term	$ 339,095	4.41%	$ 14,954.10	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	31-Dec-15	25	$ 1,995,062	3.78%	$ 75,413.34	
4	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	31-Dec-15	10	$ 246,360	2.73%	$ 6,725.63	
Total							$ 3,765,933	3.97%	$ 149,369.90	

This table must be completed for all required historical years, the bridge year and the test year.

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Espanola	Y	Fixed	Pre 2011	No Term	$ 1,185,416	4.41%	$ 52,276.83	
2	Promissory Note	Township of Sable Spanish River	Y	Fixed	Pre 2011	No Term	$ 339,095	4.41%	$ 14,954.10	
3	Promissory Note	Infrastructure Ontario	N	Fixed	31-Dec-15	25	$ 1,969,547	3.78%	$ 74,448.88	
4	Promissory Note	Infrastructure Ontario	N	Fixed	31-Dec-15	10	$ 218,423	2.73%	$ 5,962.95	
Total							$ 3,712,481	3.98%	$ 147,642.75	

This table must be completed for all required historical years, the bridge year and the test year.

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	TD Loan	Third-Party	Fixed	1-Oct-19	25	$ 7,789,530.00	2.93%	$ 228,077.44	
2	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	28-Sep-18	No Term	$ 200,000.00	3.95%	$ 7,900.00	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	25	$ 1,881,898.00	3.78%	$ 71,135.74	
4	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	10	$ 189,713.00	2.73%	$ 5,179.16	
Total							$ 10,061,141	3.10%	$ 312,292.35	

This table must be completed for all required historical years, the bridge year and the test year.

Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	TD Loan	Third-Party	Fixed	1-Oct-19	25	$ 7,789,530.00	2.93%	$ 228,077.44	
2	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	28-Sep-18	No Term	$ 200,000.00	2.45%	$ 4,900.00	
3	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	13-Apr-20	No Term	$ 265,000.00	2.45%	$ 6,492.50	
4	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate		No Term	$ 337,090.00	2.45%	$ 8,258.71	
5	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	25	$ 1,822,030	3.78%	$ 68,872.73	
6	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	10	$ 160,210	2.73%	$ 4,373.73	
7	Promissory Note	TD Loan	Third-Party	Fixed Rate	2-Sep-20	30	$ 650,000	1.84%	$ 2,990.00	
Total							$ 11,223,860	2.89%	$ 323,965.11	

This table must be completed for all required historical years, the bridge year and the test year.

Year 2021

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	TD Loan	Third-Party	Fixed	1-Oct-19	25	$ 7,789,530.00	2.93%	$ 228,077.44	
2	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	28-Sep-18	No Term	$ 200,000.00	2.45%	$ 4,900.00	
3	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	13-Apr-20	No Term	$ 265,000.00	2.45%	$ 6,492.50	
4	Grid Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	1-Jan-21	No Term	$ 572,000.00	2.45%	$ 14,014.00	
5	Promissory Note	North Bay Hydro Distribution Limited	Affiliated	Variable Rate	13-Jul-05	No Term	$ 230,000	2.45%	$ 5,635.00	
6	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	10	$ 160,210	2.73%	$ 4,373.73	
7	Promissory Note	Infrastructure Ontario	Third-Party	Fixed	31-Dec-15	25	$ 1,822,030	3.78%	$ 68,872.73	
8	Promissory Note	TD Loan	Third-Party	Fixed Rate	2-Sep-20	30	$ 645,923	1.84%	$ 11,884.98	
9	Promissory Note	TD Loan	Third-Party	Fixed Rate	10-Mar-21	30	$ 490,000	2.67%	$ 10,902.50	
Total							$ 12,174,693	2.92%	$ 355,152.89	

VECC-33

Reference: Exhibit 5, Appendix 5-A

Preamble: N/A

Question:

a) Is the TD loan with ERHDC or North Bay Hydro?

b) Please file the TD loan note.

Response:

a) The TD loan is with ERHDC.

b) Three separate TD Loan notes are provided as Appendix 3 – TD Credit Facilities Letter Agreement and Appendix 4 – TD Loan Agreement Operating Line Capital.

VECC-34

Reference: Exhibit 7, page 2
7-Staff-32 a)

Preamble:

ERHDC is proposing the following weighting factors for Services (Account 1855):

Table 7 - 1: Service Weighting Factors

Rate Class	Factor
Residential	1.0
General Service < 50 kW	0.6
General Service > 50 kW	0.7
Sentinel Lighting	0.1
Street Lights	0.1
Unmetered Scattered Load	0.1

Question:

a) If not addressed in the response to 7-Staff-32 a), please explain why the weightings for the GS<50 and GS>50 classes are less than those for the Residential class.

b) If not addressed in 7-Staff-32 a), for each of the customer classes please explain to what extent: i) ERHDC owns the Services assets and is responsible for their maintenance, ii) ERHDC is responsible for part/all of the initial capital cost (i.e., whether the customer is responsible for any capital contributions) and iii) the customer is responsible for providing and maintain the Services assets.

c) What is the basis for the $130,272 in contributed capital assigned to Services (per Tab I4 of the Cost Allocation Model)?

Response:

a) Please refer to response in OEB Staff 32 a) and b).

b) Please refer to response in OEB Staff 32 a) and b).

c) A schedule of contributed capital is kept yearly to allocate the contributed capital to the various fixed assets. ERHDC took the 2012 application amount and added in the years 2012 through 2019. An estimate of $10,000 in contributed capital was used for 2020 and 2021. The average of the beginning and ending balance was used to come up at $130,272.

VECC-35

Reference: Cost Allocation Model, Tabs I6.2, I7.1 and I7.2

Preamble: N/A

Question:

a) The Residential, GS<50 and GS>50 customer counts in Tabs I7.1 (Meter Capital) and I7.2 (Meter Reading) don't match those in Tab I6.2 (Customer Data). Please reconcile.

Response:

a) This was corrected as part of the OEB Staff Clarifying questions. The updated Cost allocation model was submitted as Attachment 7_ERHDC_2021_Cost_Allocation_Model_20210223 on February 23, 2021.

VECC-36

Reference: Exhibit 8, page 9
RTSR Workform, Tabs 3, 4 and 5

Preamble:

The Application states: "ERHDC receives wholesale transmission service from metered points that are directly connected to the Hydro One grid. ERHDC is billed Uniform Transmission Rates by Hydro One on all capacity delivered through these points."

Question:

a) The application states that ERHDC is billed UTRs. However, Tab 5 of the RTSR Workform shows HON's RTSRs being used to bill ERHDC. Please clarify whether ERHDC is billed for transmission service: i) by the IESO using the UTRs or ii) by Hydro One using its RTSRs.

b) Please confirm that the retail sales data by customer class in Tab 3 and the Units Billed data in Tab 5 are both based on the same year.

Response:

a) ERHDC is billed by Hydro One using its RTSRs.

b) Yes, the retail sales data by customer class in Tab 3 and the Units Billed data in Tab 5 are both from 2019.

VECC-37

Reference: Exhibit 8, page 10 and Appendix 8-C

Preamble: N/A

Question:

a) Please confirm that the proposed Pole Attachment charge needs to be revised to reflect the Board's EB-2020-0288 Order.

b) Does this revision impact the proposed 2021 revenues from Pole Attachment charges as set out in Exhibit 3?

Response:

a) Yes, the current Pole Attachment charge needs to be revised to reflect the Board's EB-2020-0288 Order.

Apart from this update, ERHDC also proposes the following changes.

In its Application, ERHDC had originally requested for the discontinuance of Account 1508 – Pole Attachment Revenue Variance, however, this was before the introduction of Bill 257 on March 4, 2021.

The recent Bill 257, *Supporting Broadband and Infrastructure Expansion Act, 202*1, if passed, would enact the *Building Broadband Faster Act, 2021* ("BBFA") and would result in possible increases in utility costs to facilitate broadband attachments as well as possible changes to Pole Attachment charges for broadband connections.

As the prescribed rules are yet to be known, ERHDC is proposing a new DVA to track any variances related to changes in utility costs as well as changes in Pole Attachment charges arising as a result of the BBFA.

Due to the relevant recency of the proposed legislative amendments, ERHDC is still processing the changes and will propose a draft accounting order for the new DVA prior to settlement.

b) The 2021 revenues from Pole Attachment charges do need to be revised slightly. However, this is due to a reduction in the number of poles. The number of poles for 2020 was 1801. Therefore, at a rate of $44.50 the revenues from pole attachment should be updated from $86,356 to $80,145.

VECC-38

Reference: Exhibit 8, pages 10-11

Preamble: N/A

Question:

a) Please explain how the 2020 and 2021 consumption values in Table 8-9.

b) Please provide the equivalent of Table 8-9 but based on 2019 actuals.

c) If available, please provide the equivalent of Table 8-9 based on 2020 actuals.

Response:

a) ERHDC created an adjustment factor in order to determine consumption for 2020 and 2021. This adjustment factor was created by comparing the 2020 and 2021 Weather Normalized consumption from the load forecast to the 2019 Actual consumption. The chart showing this is provided at Table VECC-38-1 below.

Table VECC-38-1 – Adjustment Factor for 2020 and 2021 Weather Normalized Consumption

	2019 Actual	2020 Weather Normal	2021 Weather Normal
Consumption	62,050,760.91	62,840,765.03	62,626,608.33
Adjustment Factor		1.27%	0.93%

ERHDC has since updated its calculation of LV charges based on actual consumption for 2020. The chart is provided in the response to part b) below.

b) Table 8-9 has been reproduced below as Table VECC-38-2 with some additional updates. First, any rate riders have been removed. The basis of the calculation is provided in the consumption, rate and annual cost columns for the respective years of 2019, 2020 and 2021. Hydro One Networks Inc. updates its rates effective January 1 of each year with the exception of an update that occurred July 1, 2019. Table 8-9 below has also been updated to include actual consumption for 2020. 2021 is still based on 2019 actual consumption and applying a conversion factor of 0.93%.

Table VECC-38-2 – Updated Table 8-9

Espanola Low Voltage Charges Estimate	2019			2020			2021		
	Rate July 1, 2019	Consumption	Annual Cost	Rate January 1, 2020	Consumption	Annual Cost	Rate January 1, 2020	Consumption	Annual Cost
Espanola Regional H 4265216004									
Common ST Lines - kW	$1.443	92,746	$122,291	$1.485	90,128	$ 133,877	$ 1.5335	93,607	$ 143,546.10
Espanola PME1 797811002									
Meter	$571.12	12	$8,011	$587.690	12	$ 7,052	$ 729.56	12	$ 8,754.72
Monthly Service Ch	$546.47	12	$6,234	$559.400	12	$ 6,713	$ 582.74	12	$ 6,992.88
LVDS - kW	$1.5386	2,911	$4,491	$1.5363	2,858	$ 4,391	$ 1.6671	2,911	$ 4,853.66
Webbwood ME 2543997004									
Meter	$571.12	12	$8,011	$587.69	12	$ 7,052	$ 729.56	12	$ 8,754.72
Monthly Service Ch	$546.47	12	$6,234	$559.40	12	$ 6,713	$ 582.74	12	$ 6,992.88
LVDS - kW	$1.5386	8,184	$12,624	$1.5363	7,738	$ 11,888	$ 1.6671	8,260	$ 13,770.16
Espanola TS - M2 2717713018									
Meter	$571.12	12	$8,011	$587.69	12	$ 7,052	$729.56	12	$ 8,754.72
Monthly Service Ch	$546.47	12	$6,234	$559.40	12	$ 6,713	$582.74	12	$ 6,992.88
Specific ST Lines - km	$480.79	30	$19,405	$480.79	30	$ 14,424	$626.09	30	$ 18,782.65
Massey ME 449121000									
Meter	$571.12	12	$8,011	$587.69	12	$ 7,052	$729.56	12	$ 8,754.72
Monthly Service Ch	$546.47	12	$6,234	$559.40	12	$ 6,713	$582.74	12	$ 6,992.88
Common ST Lines - kW	$1.4434	20,565	$26,905	$1.4854	19,650	$ 29,188	$1.5335	20,755	$ 31,828.54
HVDS - Low - kW	$3.7675	20,565	$72,669	$3.805	19,650	$ 74,763	$3.7825	20,755	$ 78,507.62
300 JACKLIN Rd 449121000									
Meter	$571.12	12	$8,011	$587.69	12	$ 7,052	$729.56	12	$ 8,754.72
Monthly Service Ch	$546.47	12	$6,234	$559.40	12	$ 6,713	$582.74	12	$ 6,992.88
LVDS	$1.5386	633	$976	$1.5363	640	$ 983	$1.6671	639	$ 1,064.83
	Total of All Meters		**$330,586**			**$338,496**			**$371,092**

c) The 2020 actual are provided in the response to part b) above.

VECC-39

Reference: Exhibit 8, page 13

Preamble: N/A

Question:

a) Please explain how the Supply Facilities Loss Factor was calculated for each of the years 2015-2019.

Response:

ERHDC has provided a more detailed breakout of Chapter 2 Appendices, Appendix 2-R Loss Factors in Table VECC-39 below. Two additional columns have been included showing an additional row description and how the values reconcile to section 2.1.5 of the RRR filings. Rows 10 and 14 have been added to show the amount related to embedded generation and Long Term Load Transfer respectively.

Table VECC-39 – Updated Appendix 2-R – Loss Factors

				Historical Years					5-Year Average
		Description	RRR Reconcile	2015	2016	2017	2018	2019	
	Losses Within Distributor's System								
A(1)	"Wholesale" kWh delivered to distributor (higher value)			61,027,107	59,711,876	58,757,254	60,659,212	61,089,144	60,248,919
A(2)	"Wholesale" kWh delivered to distributor (lower value)	Amount from Hydro One without loss	A) i)	60,115,154	59,065,335	57,552,835	58,660,394	59,083,418	58,895,427
		Amount from Embedded Generation	A) ii)	77,614	82,228	734,080	1,150,921	975,461	604,061
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)								-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**			60,192,768	59,147,563	58,286,915	59,811,315	60,058,879	59,499,488
D	"Retail" kWh delivered by distributor	total kWhs of Electricity delivered to all customers in the distributors licensed service area and to any embedded distributors	B) i)	58,546,499	56,466,454	54,872,263	57,113,840	57,482,828	56,896,377
		total kWhs of electricity delivered on LTLT Arrangement	B) ii)	212,588	178,345	175,647	89,012	-	131,118
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)								-
F	Net "Retail" kWh delivered by distributor = **D - E**			58,759,087	56,644,799	55,047,910	57,202,852	57,482,828	57,027,495
G	Loss Factor in Distributor's system = **C / F**			1.0244	1.0442	1.0588	1.0456	1.0448	1.0433
	Losses Upstream of Distributor's System								
H	Supply Facilities Loss Factor			1.0152	1.0109	1.0209	1.0341	1.0339	1.0230
	Total Losses								
I	Total Loss Factor = **G x H**			1.0399	1.0556	1.0810	1.0812	1.0803	1.0673

VECC-40

Reference: Exhibit 9, page

Preamble: N/A

Question:

a) Please provide the current balance in Account 1509 – Impacts Arising from the COVID-19 emergency.

Response:

a) Please refer to the response in CCC-4.

VECC-41

Reference: Exhibit 9, page

Preamble: N/A

Question:

a) When was the last time ERHDC disposed of its Group 1 DVAs?

b) The RSVA - Retail Transmission Connection Charge balance has been systemically accumulating since 2014. Is this due to the RTSR charge systemically undercharging for this service?

c) If yes, please explain why did ERHDC not seek to adjust the RTSR at an earlier date.

Response:

a) ERHDC last disposed of Group 1 DVAs in 2015 which was for 2013 Year End balances.

b) The RTSR Connection Charge has been accumulating due to a misplacement of the recording of the Hydro One bills. Charges that should have been recorded in the Low Voltage Accounts was erroneously being recorded as RTSR connection charges. The Low Voltage Variance account has a credit to customers of $219,634. This would have partially offset the collection of $930,863 and RTSR Connection Charges.

c) Please refer to response to CCC-2. ERHDC intended to adjust the RTSR at its next rebasing after group 1 DVA's were last disposed of in 2015.

Appendix 1 – Letters of Comment Reply

APPENDIX 1

Letters of Comment Reply

Espanola Regional Hydro Distribution Corporation
598 Second Avenue
Espanola, ON P5E 1C4

March 25, 2020

Ms Jennifer Marenger,

Thank you for taking the time to comment on Espanola Regional Hydro's 2021 Cost of Service Application for changed rates effective May 1, 2021. We appreciate all customer feedback and the time you took to submit your comments.

We completely understand and appreciate your concern with the rising cost of electricity, and the effect that it will have on the community. We also understand that during this time of the pandemic it has been especially difficult to deal with the unexpected. We want to assure you that we work hard to keep the portion of the bill we have control over, as low as possible. However, to continue to provide a safe and reliable supply of electricity to Espanola Regional Hydro customers, additional revenue is needed to continue addressing our community's aging infrastructure and the rising costs associated with its operation.

Espanola Regional Hydro has taken various measures to mitigate rate impacts, such as adjusting the revenue to cost ratios of the Sentinel Light rate class, collecting amounts owing under certain Deferral and Variance Accounts over 5 years instead of 1, and moving to fully fixed residential rates over the next five years. The concern around the affordability of electricity is an issue that is not unique to Espanola Regional Hydro customers; in fact, it is one that is shared by many Ontarians across the province. In response to these worries, the Province established a number of programs to assist consumers struggling with their electricity bill.

Information for these assistance programs are provided in Espanola Regional Hydro customer's electricity bills. Nevertheless, we want to take this opportunity to mention a few of the special programs that are available to help low-income energy consumers:

Ontario Electricity Support Program (OESP) (www.ontarioelectricitysupport.ca)

This program provides ongoing help for low-income consumers with a monthly on-bill credit to reduce their electricity bill.

COVID-19 Energy Assistance Programs (CEAP)

This program makes funding available to support residential, small business and charitable organization customers that are struggling to pay their energy bills as a result of the COVID-19 emergency. CEAP provides a one-time credit to eligible residential electricity customers to help them catch up on their energy bills and resume regular payments.

Espanola Regional Hydro Distribution Corporation
598 Second Avenue
Espanola, ON P5E 1C4

Low-income Energy Assistance Program (LEAP)

This program (for emergency situations) provides a one-time grant towards your electricity or natural gas bill if you are behind on your bill and may face having your service shut off. The intake agency that provides this service in Manitoulin-Sudbury District Services Board, and they can be reached at 705-862-7850.

Arrears Management Program

As prescribed by the Ontario Energy Board, eligible customers who are unable to pay their outstanding electricity charges may enter into an arrears payment agreement with Espanola Regional Hydro. The agreement allows the outstanding arrears to be paid in instalments over a number of months, and may require that a portion of the arrears be paid as a down payment. The customer is also required to continue to pay their regular ongoing electricity bills.

Thank you again for your comments and please contact us again should you have questions or concerns.

Sincerely,
Espanola Regional Hydro

Espanola Regional Hydro Distribution Corporation
598 Second Avenue
Espanola, ON P5E 1C4

March 25, 2020

Mr. Robert Hunter,

Thank you for taking the time to comment on Espanola Regional Hydro's 2021 Cost of Service Application for changed rates effective May 1, 2021. We appreciate all customer feedback and the time you took to submit your comments.

We understand that there are instances where Espanola Regional Hydro's customers experience payment issues from time to time, which can extend from a multitude of reasons. One of those reasons could be the result of increasing costs associated with the delivery of power to homes, schools and businesses. We want to assure you that we work hard to keep the portion of the bill we have control over, as low as possible. However, to continue to provide a safe and reliable supply of electricity to Espanola Regional Hydro customers, additional revenue is needed to continue addressing our community's aging infrastructure and the rising costs associated with its operation.

Espanola Regional Hydro has taken various measures to mitigate rate impacts, such as adjusting the revenue to cost ratios of the Sentinel Light rate class, collecting amounts owing under certain Deferral and Variance Accounts over 5 years instead of 1, and moving to fully fixed residential rates over the next five years. The concern around the affordability of electricity is an issue that is not unique to Espanola Regional Hydro customers; in fact, it is one that is shared by many Ontarians across the province. In response to these worries, the Province established a number of programs to assist consumers struggling with their electricity bill.

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Thank you again for your comments and please contact us again should you have questions or concerns.

Sincerely,
Espanola Regional Hydro

Appendix 2 – Board Presentation

Espanola Regional Hydro Distribution Corp.

Cost of Service Rate Application

November 17, 2020

2021 Test Year Budget Direction

- Approval from the Board to file the Cost of Service Rate application based on the following 2021 budget
- For the rate application ERHDC is required to project:
  - OM&A expenses
  - Depreciation
  - Capital Expenditures

2021 Test Year Budget Inputs

- 2021 OM&A budget based on 2020 ERHDC Board approved budget
- Labour rate increase of 1.75% in 2021 as per collective agreement
- Other OM&A expenses increased 1.5%
- Admin expenses also increased $200,000 for CoS rate application expense (total of $1.0 million over 5 year rate life cycle)
- Depreciation expense based on 2020 asset balance plus 2021 additions
- Payment in Lieu of Taxes (income tax) – estimating no PILs in 2021 (2019 loss carry-forward of $351k and CCA in excess of deprec.)
- Capital expenditure budget based on customer demand and system renewal

Espanola Regional Hydro Distribution Inc.
Results of Operations

	For the Year Ending December 31			
		2020 Estimated		2021 Budget
Revenue				
Net Electricity Distribution Revenue	$	1,605,977	$	2,094,396
Other Revenue	$	156,323	$	143,862
	$	1,762,300	$	2,238,258
Expenses				
Operations	$	723,495	$	734,963
Billing, Collecting & Administrative	$	809,111	$	1,021,352
Operating Expenses	$	1,532,606	$	1,756,315
Depreciation	$	177,755	$	229,039
Operating and Depreciation	$	1,710,361	$	1,985,354
Income from Operating	$	51,939	$	252,904
Interest Expense	$	366,795	$	386,453
Income before taxes	$	(314,856)	$	(133,549)
Income taxes	$	-	$	-
Net Income	$	(314,856)	$	(133,549)

2021 Capital Budget

SYSTEM RENEWAL:	
OH Distribution:	
Pole Replacements	$ 75,615
OH Transformer Renewal	$ 40,654
OH Cutout Renewal	$ 9,547
Clearlake	$ 41,821
OH Forced Outages	$ 5,587
Massey, 3 phase line Hwy 17 / Bell St vs over rock on Ca	$ 126,423
Total OH Distribution	***$ 299,647***
UG Distribution:	
Kbar replacement	$ 12,268
Replace Transclosures	$ 38,795
UG Forced Outages	$ 2,925
Replace Submarine Cable	$ -
Total UG Distribution	***$ 53,987***
Substations:	
MS 3 Conductor replacement	$ 46,318
Substation Misc Projects	$ 3,612
Total Substation	***$ 49,930***
Total System Renewal	**$ 403,565**

SYSTEM ACCESS:	
Upgrade Services	$ 4,514
New Services	$ 20,513
Brentwood subdivision	$ -
Joint use	$ 2,656
City Projects - Line Relocations	$ 7,762
Meters	$ 7,161
Per five year metering plan - 8 meters to re-seal	$ 9,258
Total System Access	**$ 51,864**

GENERAL PLANT:	
Buildings - New door, insulate and heat building	$ 20,000
Facilities Misc	$ 5,000
Tools & Equipment	$ 8,000
Total General Plant	**$ 33,000**
Total Capital before Contributions	**$ 488,429**
Grants/Contributions	**$ (25,000)**
TOTAL CAPITAL SPENDING	**$ 463,429**

Rate Increase Drivers

- Last distribution rate increase was 2015
- Last cost of service application was 2012

- Items affecting the monthly bill
    - Distribution revenue increase
    - Recovery of regulatory assets
    - Recovery of LRAM
    - Transition to fully fixed rates for residential customers
    - Cost allocation update
    - Retail Transmission rate increase

Rate Mitigation Plan

- In order to reduce the impact on customers the following was implemented:

- 1. LRAM recovery over 5 years
- 2. Regulatory asset recovery over 5 years
- 3. Accelerated depreciation credit over 1 year
- 4. Pole rental credit over 1 year
- 5. Residential class transition to fully fixed monthly charge over 5 years rather than the typical 4 years
- 6. Smoothed approach to reach Cost Allocation targets over 5 years

Rate Impacts prior to and after rate mitigation

Class	Consumption (kWh)	Consumption (kW)	4yr F/V Transition and 1yr Rate Rider Total Bill Increase/Decrease	 Total Bill Impact %	5yr F/V Transition and 5yr Rate Riders Total Bill Increase/Decrease	 Total Bill Impact %
Residential	750	0	$20.29	16.85%	$9.12	7.57%
Residential	318	0	$12.85	21.97%	$7.31	12.48%
Residential	848	0	$21.98	16.35%	$9.53	7.09%
GS<50	2,386	0	$66.76	17.73%	$25.48	6.88%
GS>50	44,361	115	$253.77	2.82%	$207.58	2.31%
USL	456	0	$12.14	16.02%	$5.66	7.52%
Sentinel Light	81	0.22	$10.70	48.29%	$3.44	15.52%
Street Light - Espanola	14238	41.8	$2,383.74	58.54%	$494.76	12.15%
Street Light Massey	4508	13.23	$856.86	58.03%	$308.20	20.87%


Q&A

Appendix 3 - TD Credit Facilities Letter Agreement

TD Commercial Banking

Northern Ontario Commercial Banking Group
240 Main Street East
North Bay, Ontario
P1B 1B1

Telephone No.: (705) 495 6715
Fax No.: (705) 474 6297

September 19, 2019

NORTH BAY (ESPANOLA) ACQUISITION INC.
74 Commerce Court
North Bay, ON
P1B 8Y5

Attention: Mr. Matthew Payne

Dear Matthew,

We are pleased to offer the Borrower the following credit facilities (the "Facilities"), subject to the following terms and conditions.

BORROWER

NORTH BAY (ESPANOLA) ACQUISITION INC. (the "Borrower")

LENDER

The Toronto-Dominion Bank (the "Bank"), through its Northern Ontario Commercial Banking Group in North Bay, Ontario.

CREDIT LIMIT

1) CAD$8,000,000
2) CAD$2,200,000
3) CAD$500,000

TYPE OF CREDIT AND BORROWING OPTIONS

1) **Committed Reducing Term Facility (Single Draw)** available at the Borrower's option by way of:
   - Fixed Rate Term Loan in CAD$
   - Floating Rate Term Loan available by way of:
      - Bankers Acceptances in CAD$

2) **Committed Reducing Term Facility (Single Draw)** available at the Borrower's option by way of:
- Fixed Rate Term Loan in CAD$
- Floating Rate Term Loan available by way of:
  - Bankers Acceptances in CAD$

3) **Operating Loan** available at the Borrower's option by way of:
- Prime Rate Based Loans in CAD$ ("Prime Based Loans")

PURPOSE

1) To purchase the shares of Espanola Regional Hydro.
2) For repayment of existing Espanola Regional Hydro OSIFA debt.
3) To fund working capital.

TENOR

1, 2) Committed
3) Uncommitted

CONTRACTUAL TERM

1) 60 month(s) from the date of drawdown
2) 60 month(s) from the date of drawdown
3) No term

RATE TERM (FIXED RATE TERM LOAN)

1, 2) Fixed rate: 6 month, 12-60 months but never to exceed the Contractual Term Maturity Date
Floating rate: No term

AMORTIZATION

1) 360 month(s)
2) 264 month(s)

INTEREST RATES AND FEES

Advances shall bear interest and fees as follows:

1) **Committed Reducing Term Facility:**
- Fixed Rate Term Loans: as determined by the Bank, in its sole discretion, for the Rate Term selected by the Borrower, and as set out in the Rate and Payment Terms Notice applicable to that Fixed Rate Term Loan.
- Floating Rate Term Loans available by way of:
  - B/As: as set out by the Bank, in its sole discretion, for the Rate Term selected by the Borrower, and as set out in the Swap Confirmation applicable to that Loan.

2) **Committed Reducing Term Facility:**

- Fixed Rate Term Loans: as determined by the Bank, in its sole discretion, for the Rate Term selected by the Borrower, and as set out in the Rate and Payment Terms Notice applicable to that Fixed Rate Term Loan.
- Floating Rate Term Loans available by way of:
  - B/As: as set out by the Bank, in its sole discretion, for the Rate Term selected by the Borrower, and as set out in the Swap Confirmation applicable to that Loan.

3) **Operating Loan:**

- Prime Based Loans: Prime Rate + 0.000% per annum

DRAWDOWN

1, 2) One time drawdown prior to December 31, 2020, after which time, any amount not drawn is cancelled. Amounts repaid may not be redrawn.

3) On a revolving basis.

BUSINESS CREDIT SERVICE

The Borrower will have access to the Operating Loan (Facility 3) via Loan Account Number 3120-9240660 (the "Loan Account") up to the Credit Limit of the Operating Loan by withdrawing funds from the Borrower's Current Account Number 3120-5240660 (the "Current Account"). The Borrower agrees that each advance from the Loan Account will be in an amount equal to $5,000 (the "Transfer Amount") or a multiple thereof. If the Transfer Amount is NIL, the Borrower agrees that an advance from the Borrower's Loan Account may be in an amount sufficient to cover the debits made to the Current Account.

The Bank may, but is not required to, automatically advance the Transfer Amount or a multiple thereof or any other amount from the Loan Account to the Current Account in order to cover the debits made to the Current Account if the amount in the Current Account is insufficient to cover the debits. The Bank may, but is not required to, automatically and without notice apply the funds in the Current Account in amounts equal to the Transfer Amount or any multiple thereof or any other amount to repay the outstanding amount in the Loan Account.

REPAYMENT AND REDUCTION OF AMOUNT OF CREDIT FACILITY

1,2) All amounts outstanding will be repaid on or before the Contractual Term Maturity Date. The drawdown will be repaid in equal monthly payments. The Borrower also has the option to pay interest only for 3 years from the original funding date. The details of repayment and interest rate applicable to such drawdown will be set out in the" Rate and Payment Terms Notice" applicable to that drawdown. Any amounts repaid may not be reborrowed.

Notwithstanding the foregoing, drawdowns by BA or LIBOR Loan will not be repaid in periodic instalments as set out above, but rather will be repaid at the end of the term of the BA or LIBOR Loan by the Borrower making another drawdown up to the amount of the Credit Limit as such Credit Limit is reduced using the amortization period set out herein.

Amortization is inclusive of the interest only period of up to 3 years. The amortization of the facility begins at the date of funding the original advance and includes any interest only period utilized.

3) On demand. If the Bank demands repayment, the Borrower will pay to the Bank all amounts outstanding under the Operating Loan and the amount of all drawn and undrawn L/Gs and L/Cs. All costs to the Bank and all loss suffered by the Bank in re-employing the amounts so repaid will be paid by the Borrower.

PREPAYMENT

1, 2) Fixed Rate Loans: the Borrower can utilize the 10% Prepayment Option and accordingly, Fixed Rate Term Loans under this Facility may be prepaid in accordance with Section 4a) and 4b) of Schedule A.
If an Interest Rate Swap is used prepayment is subject to unwinding costs.

3) Permitted at any time without penalty.

SECURITY

The following security shall be provided, unless otherwise indicated, support all present and future indebtedness and liability of the Borrower and the grantor of the security to the Bank including without limitation indebtedness and liability under guarantees, foreign exchange contracts, cash management products, and derivative contracts, shall be registered in first position, and shall be on the Bank's standard form, supported by resolutions and solicitor's opinion, all acceptable to the Bank.

a) A resolution of the board of directors of the Borrower authorizing the execution and delivery of this Agreement, the ISDA Agreement, the Bank Security (as defined below) and the borrowing under the Facilities (the "**Borrowing Resolution**");
b) a general security agreement ("**GSA**") representing a first charge on all of the Borrower's present and after acquired personal property;
c) Inter-creditor agreement between Ontario Infrastructure and Lands Corporation and the Bank;
d) Guarantee of Advances
   - Limited to 100.000% of the Borrower's outstanding debt with the Bank;
   - Executed by NORTH BAY HYDRO DISTRIBUTION LIMITED (the "**Guarantor**");
e) copy of the insurance policy in respect of Espanola Regional Hydro Distribution Corporation issued by MEARIE Group; and
f) confirmations of guarantee and security post-Amalgamation (as defined below).

All persons and entities required to provide a guarantee shall be referred to in this Agreement individually as a "Surety" and/or "Guarantor" and collectively as the "Guarantors";

All of the above security and guarantees shall be referred to collectively in this Agreement as **"Bank Security"**.

DISBURSEMENT CONDITIONS

The obligation of the Bank to permit any drawdown hereunder is subject to the Standard Disbursement Conditions contained in Schedule "A" and the following additional drawdown conditions:

Delivery to the Bank of the following, all of which must be satisfactory to the Bank:

All) If a 30 year amortization period is chosen for Facility #1, the Borrower will provide evidence satisfactory to the Bank of the following:
   a. the Borrower is indirectly owned by The Corporation of the City of North Bay (the "**Municipality**") and will remain indirectly owned by the Municipality following the amalgamation of the Borrower with Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation (the "**Amalgamation**");
   b. the Borrower's financial statements will be reviewed by the Municipality; and
   c. the Borrower's budgets will be reviewed by the Municipality;

All) Delivery of executed copies of the Resolutions to the Bank;

All) Delivery of a legal opinion to the Bank from counsel to the Borrower with respect to its existence and the due authorization, execution and delivery of this Agreement, the ISDA Agreement and the Bank Security;

All) Delivery of an executed ISDA Agreement if borrowing by way of interest rate swap;

All) Delivery of an executed copy of the securities purchase agreement dated October 12, 2018 between the Borrower, The Corporation of the Town of Espanola, The Corporation of the Township of Sables-Spanish Rivers and North Bay Hydro Holdings Ltd. (the "**SPA**");

All) A copy of Decision and Order EB-2019-0015 from the Ontario Energy Board approving the Borrower's acquisition of Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation and the Amalgamation;

All) Delivery of the recent quarterly financial statements for the Borrower (prior to the Amalgamation) and the Guarantor;

All) Confirmation from a senior officer of the Borrower that there has been no material adverse change in the financial condition and/or operations of the Borrower; and

All) All security to be on hand and in good order as confirmed by the Bank and the Bank's solicitor.

REPRESENTATIONS AND WARRANTIES

All representations and warranties shall be deemed to be continually repeated so long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect. The Borrower makes the Standard Representations and Warranties set out in Schedule "A".

POSITIVE COVENANTS

So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower will and will ensure that its subsidiaries and each of the Guarantors will observe the Standard Positive Covenants set out in Schedule "A" and in addition will:

All) Provide annual Audited Financial Statements within 120 calendar days of fiscal year end;

All) Provide annual Business Plan within 120 calendar days of fiscal year end, including an Income Statement, Balance Sheet, Statement of Changes in Financial Position and Capital Budget;

All) Ensure Borrower remains in the business of electricity distribution and maintains all licenses required by the OEB to do so;

All) Maintain compliance with all applicable environmental regulations at all times;

All) Maintain compliance with all contractual obligations and laws, including payment of taxes;

All) Maintain compliance with terms of all licenses and immediately advise the Bank if OEB notifies the Borrower of a default under its license, or if its license is cancelled, amended, suspended or revoked (any such circumstances will constitute an event of default);

All) Maintain compliance with the "Affiliate Relationship Code";

All) Maintain adequate insurance;

All) Provide copy of all OEB rate submissions;

All) Provide a copy of the articles of amalgamation in respect of the Borrower, Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation following the completion of the Amalgamation on the closing date of the transactions set forth in the SPA; and

All) Provide a copy of the articles of dissolution of Espanola Regional Hydro Services Corporation within 5 days following the dissolution of Espanola Regional Hydro Services Corporation.

NEGATIVE COVENANTS

So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower will and will ensure that its subsidiaries and each of the Guarantors will observe the Standard Negative Covenants set out in Schedule "A". In addition the Borrower will not and will ensure that its subsidiaries and each of the Guarantors will not:

All) Make Distributions (including dividends, interest and principal reductions on shareholder's promissory note) in excess of Free Cashflow unless financed by cash on hand. Free Cashflow is defined as

EBITDA less Payment in Lieu of Taxes less Unfinanced Capital Expenditures (net of contributed capital) less interest costs (excluding shareholder note interest) and less Principal payments if any;

All) pledge its assets, subject to existing and permitted Encumbrances (including the outstanding indebtedness with Ontario Infrastructure and Lands Corporation), except for Permitted Liens;

All) incur additional indebtedness, including issuing guarantees, without the Bank's prior written consent except for (i) trade accounts and expenses incurred in the ordinary course of business, (ii) unsecured, subordinated loans made by the Guarantor to the Borrower, and (iii) the existing indebtedness of the Guarantor to the Bank, Ontario Infrastructure and Lands Corporation and trade accounts and expenses incurred in the ordinary course of its business;

All) permit a change in ownership structure to occur without prior notice to the Bank;

All) following the Amalgamation, a change in the status of the Borrower as a licensed electricity distributor with the Ontario Energy Board (the "**OEB**"); and

All) No mergers or amalgamations without the Bank's prior written consent, except for the amalgamation of the Borrower with the Guarantor (subject to receipt of the approval of the OEB).

PERMITTED LIENS

Permitted Liens as referred to in Schedule "A" are:

Purchase Money Security Interests in equipment which Purchase Money Security Interests exist on the date of this Agreement ("Existing PMSIs") which are known to the Bank and all future Purchase Money Security Interests on equipment acquired to replace the equipment under Existing PMSIs, provided that the cost of such replacement equipment may not exceed the cost of the equipment subject to the Existing PMSI by more than 10%

Any liens, security interests and encumbrances consented to by the Bank pursuant to the inter-creditor agreement between Ontario Infrastructure and Lands Corporation and the Bank.

With respect to the Guarantor, any liens, security interests and encumbrances in favour of the Bank and Ontario Infrastructure and Lands Corporation.

FINANCIAL COVENANTS

The Borrower and Guarantor agree, on a consolidated basis, to:

All) Maintain a Debt Service Coverage (DSC) of not less than 1.20:1. Tested on an annual basis commencing December 31, 2022. The DSC is calculated as follows:

If Unfinanced CAPEX is less than 40% of Capital Expenditures:

[EBITDA - Payments in Lieu of Taxes - Unfinanced CAPEX (net of contributed surplus and proceeds on sale of property, plant, and equipment)] / (Principal + Interest + Capital Leases)

OR

If 40% of Capital Expenditures is less than Unfinanced CAPEX:

[EBITDA - Payments in Lieu of Taxes - 40% of Capital Expenditures (net of contributed surplus and proceeds on sale of property, plant, and equipment)] / (Principal + Interest + Capital Leases)

EBITDA is defined as Earnings before Interest, Income Taxes, Depreciation, and Amortization.

Interest excludes any interest generated on customer deposits and regulatory liabilities.

Unfinanced CAPEX is defined as total Capital Expenditures less loans drawn to pay for Capital Expenditures.

AII) Maximum Debt to Capitalization Ratio of 0:60:1, tested on an annual basis commencing December 31, 2022.
Debt is defined as all interest-bearing debt not subordinated to these credit facilities excluding customer deposits and regulatory liabilities.

Capitalization is defined as total interest bearing debt excluding customer deposits and regulatory liabilities, plus shareholder's equity, plus contributed capital, plus preference share capital, less goodwill and intangible assets.

EVENTS OF DEFAULT

The Bank may accelerate the payment of principal and interest under any committed credit facility hereunder and cancel any undrawn portion of any committed credit facility hereunder, at any time after the occurrence of any one of the Standard Events of Default contained in Schedule "A" attached hereto and after any one of the following additional Events of Default:

a) Any material adverse change in legislation or the regulation of the electrical distribution business.

b) Default of any of the aforementioned terms and conditions.

c) Loss of OEB license.

d) Material judgements, or other executions against the Borrower.

ANCILLARY FACILITIES

As at the date of this Agreement, the following uncommitted ancillary products are made available. These products may be subject to other agreements.

1) Certain treasury products, such as forward foreign exchange transactions, and/or interest rate and currency and/or commodity swaps.

The Borrower agrees that treasury products will be used to hedge its risk and will not be used for speculative purposes.

SCHEDULE "A" - STANDARD TERMS AND CONDITIONS

Schedule "A" sets out the Standard Terms and Conditions ("Standard Terms and Conditions") which apply to these credit facilities. The Standard Terms and Conditions, including the defined terms set out therein, form part of this Agreement, unless this letter states specifically that one or more of the Standard Terms and Conditions do not apply or are modified.

We trust you will find these facilities helpful in meeting your ongoing financing requirements. We ask that if you wish to accept this offer of financing (which includes the Standard Terms and Conditions), please do so by signing and returning the attached duplicate copy of this letter to the undersigned. This offer will expire if not accepted in writing and received by the Bank on or before **October 31, 2019.**

Yours truly,

THE TORONTO-DOMINION BANK

Jonathan Loewen Account Manager	Andrew Crawford Manager Commercial Credit

TO THE TORONTO-DOMINION BANK:

NORTH BAY (ESPANOLA) ACQUISITION INC. hereby accepts the foregoing offer this 26th day of SEPTEMBER, 2019. The Borrower confirms that, except as may be set out above, the credit facility(ies) detailed herein shall not be used by or on behalf of any third party.

Signature

MATT PAYNE, PRESIDENT + C.O.O.
Print Name & Position

Signature

VP. FINANCE
Print Name & Position

cc. Guarantor(s)

The Bank is providing the guarantor(s) with a copy of this letter as a courtesy only. The delivery of a copy of this letter does not create any obligation of the Bank to provide the guarantor(s) with notice of any changes to the credit facilities, including without limitation, changes to the terms and conditions, increases or decreases in the amount of the credit facilities, the establishment of new credit facilities or otherwise. The Bank may, or may not, at its option, provide the guarantor(s) with such information, provided that the Bank will provide such information upon the written request of the guarantor.

SCHEDULE A
STANDARD TERMS AND CONDITIONS

1. INTEREST RATE DEFINITIONS

Prime Rate means the rate of interest per annum (based on a 365 day year) established and reported by the Bank to the Bank of Canada from time to time as the reference rate of interest for determination of interest rates that the Bank charges to customers of varying degrees of creditworthiness in Canada for Canadian dollar loans made by it in Canada.

The Stamping Fee rate per annum for CAD B/As is based on a 365 day year and the Stamping Fee is calculated on the Face Amount of each B/A presented to the Bank for acceptance. The Stamping Fee rate per annum for USD B/As is based on a 360 day year and the Stamping Fee is calculated on the Face Amount of each B/A presented to the Bank for acceptance.

CDOR means, for any day, the annual rate for B/As denominated in Canadian Dollars for a specified term that appears on the Reuters Screen CDOR Page as of 10:00 a.m. (Toronto time) on such day (or, if such day is not a Business Day, then on the immediately preceding Business Day).

LIBOR means the rate of interest per annum (based on a 360 day year) as determined by the Bank (rounded upwards, if necessary to the nearest whole multiple of 1/16th of 1%) at which the Bank may make available United States dollars which are obtained by the Bank in the Interbank Euro Currency Market, London, England at approximately 11:00 a.m. (Toronto time) on the second Business Day before the first day of, and in an amount similar to, and for the period similar to the interest period of, such advance.

USBR means the rate of interest per annum (based on a 365 day year) established by the Bank from time to time as the reference rate of interest for the determination of interest rates that the Bank charges to customers of varying degrees of creditworthiness for US dollar loans made by it in Canada.

If Prime Rate, CDOR, LIBOR, USBR or any other applicable base rate is less than zero, such base rate shall be deemed to be zero for purposes of this Agreement.

Any interest rate based on a period less than a year expressed as an annual rate for the purposes of the Interest Act (Canada) is equivalent to such determined rate multiplied by the actual number of days in the calendar year in which the same is to be ascertained and divided by the number of days in the period upon which it was based.

2. INTEREST CALCULATION AND PAYMENT

Interest on Prime Based Loans and USBR Loans is calculated daily (including February 29 in a leap year) and payable monthly in arrears based on the number of days the subject loan is outstanding unless otherwise provided in the Rate and Payment Terms Notice. Interest is charged on February 29 in a leap year.

The Stamping Fee is calculated based on the amount and the term of the B/A and is payable upon acceptance by the Bank of the B/A. The net proceeds received by the Borrower on a B/A advance will be equal to the Face Amount of the B/A discounted at the Bank's then prevailing B/A discount rate for CAD B/As or USD B/As as the case may be, for the specified term of the B/A less the B/A Stamping Fee. If the B/A discount rate (or the rate used to determine the B/A discount rate) is less than zero, it shall instead be deemed to be zero for purposes of this Agreement.

Interest on LIBOR Loans and CDOR Loans is calculated and payable on the earlier of contract maturity or quarterly in arrears, for the number of days in the LIBOR or CDOR interest period, as applicable.

L/C and L/G fees are payable at the time set out in the Letter of Credit Indemnity Agreement applicable to the issued L/C or L/G.

Interest on Fixed Rate Term Loans is compounded monthly and payable monthly in arrears unless otherwise provided in the Rate and Payment Terms Notice.

Interest is payable both before and after maturity or demand, default and judgment.

Each payment under this Agreement shall be applied first in payment of costs and expenses, then interest and fees and the balance, if any, shall be applied in reduction of principal.

For loans not secured by real property, all overdue amounts of principal and interest and all amounts outstanding in excess of the Credit Limit shall bear interest from the date on which the same became due or from when the excess was incurred, as the case may be, until the date of payment or until the date the excess is repaid at the Bank's standard rate charged from time to time for overdrafts, or such lower interest rate if the Bank agrees to a lower interest rate in writing. Nothing in this clause shall be deemed to authorize the Borrower to incur loans in excess of the Credit Limit.

If any provision of this Agreement would oblige the Borrower to make any payment of interest or other amount payable to the Bank in an amount or calculated at a rate which would be prohibited by law or would result in a receipt by the Bank of "interest" at a "criminal rate" (as such terms are construed under the Criminal Code (Canada)), then, notwithstanding such provision, such amount or rate shall be deemed to have been adjusted with retroactive effect to the maximum amount or rate of interest, as the case may be, as would not be so prohibited by applicable law or so result in a receipt by the Bank of "interest" at a "criminal rate", such adjustment to be effected, to the extent necessary (but only to the extent necessary), as follows: first, by reducing the amount or rate of interest, and, thereafter, by reducing any fees, commissions, costs, expenses, premiums and other amounts required to be paid to the Bank which would constitute interest for purposes of section 347 of the Criminal Code (Canada).

3. DRAWDOWN PROVISIONS

Prime Based and USBR Loans

There is no minimum amount of drawdown by way of Prime Based Loans and USBR Loans, except as stated in this Agreement. The Borrower shall provide the Bank with 3 Business Days' notice of a requested Prime Based Loan or USBR Loan over $1,000,000.

B/As

The Borrower shall advise the Bank of the requested term or maturity date for B/As issued hereunder. The Bank shall have the discretion to restrict the term or maturity dates of B/As. In no event shall the term of the B/A exceed the Contractual Term Maturity Date or Maturity Date, as applicable. Except as otherwise stated in this Agreement, the minimum amount of a drawdown by way of B/As is $1,000,000 and in multiples of $100,000 thereafter. The Borrower shall provide the Bank with 3 Business Days' notice of a requested B/A drawdown.

The Borrower shall pay to the Bank the full amount of the B/A at the maturity date of the B/A.

The Borrower appoints the Bank as its attorney to and authorizes the Bank to (i) complete, sign, endorse, negotiate and deliver B/As on behalf of the Borrower in handwritten form, or by facsimile or mechanical signature or otherwise, (ii) accept such B/As, and (iii) purchase, discount, and/or negotiate B/As.

LIBOR and CDOR

The Borrower shall advise the Bank of the requested LIBOR or CDOR contract maturity period. The Bank shall have the discretion to restrict the LIBOR or CDOR contract maturity. In no event shall the term of the LIBOR or CDOR contract exceed the Contractual Term Maturity Date. Except as otherwise stated in this Agreement, the minimum amount of a drawdown by way of a LIBOR Loan or a CDOR Loan is $1,000,000, and shall be in multiples of $100,000 thereafter. The Borrower will provide the Bank with 3 Business Days' notice of a requested LIBOR Loan or CDOR Loan.

L/C and/or L/G

The Bank shall have the discretion to restrict the maturity date of L/Gs or L/Cs.

B/A, LIBOR and CDOR - Conversion
Any portion of any B/A, LIBOR or CDOR Loan that is not repaid, rolled over or converted in accordance with the applicable notice requirements hereunder shall be converted by the Bank to a Prime Based Loan effective as of the maturity date of the B/A or the last day in the interest period of the LIBOR or CDOR contract, as applicable. The Bank may charge interest on the amount of the Prime Based Loan at the rate of 115% of the rate applicable to Prime Based Loans for the 3 Business Day period immediately following such maturity. Thereafter, the rate shall revert to the rate applicable to Prime Based Loans.

B/A, LIBOR and CDOR – Market Disruption
If the Bank determines, in its sole discretion, that a normal market in Canada for the purchase and sale of B/As or the making of CDOR or LIBOR Loans does not exist, any right of the Borrower to request a drawdown under the applicable borrowing option shall be suspended until the Bank advises otherwise. Any drawdown request for B/As, LIBOR or CDOR Loans, as applicable, during the suspension period shall be deemed to be a drawdown notice requesting a Prime Based Loan in an equivalent amount.

Cash Management
The Bank may, and the Borrower hereby authorizes the Bank to, drawdown under the Operating Loan, Agriculture Operating Line or Farm Property Line of Credit to satisfy any obligations of the Borrower to the Bank in connection with any cash management service provided by the Bank to the Borrower. The Bank may drawdown under the Operating Loan, Agriculture Operating Line or Farm Property Line of Credit even if the drawdown results in amounts outstanding in excess of the Credit Limit.

Notice
Prior to each drawdown under a Fixed Rate Term Loan, other than a Long Term Farm Loan, an Agriculture Term Loan, a Canadian Agricultural Loans Act Loan, a Dairy Term Loan or a Poultry Term Loan and at least 10 days prior to the maturity of each Rate Term, the Borrower will advise the Bank of its selection of drawdown options from those made available by the Bank. The Bank will, after each drawdown, other than drawdowns by way of BA, CDOR, or LIBOR Loan or under the operating loan, send a Rate and Payment Terms Notice to the Borrower.

4. PREPAYMENT

Fixed Rate Term Loans

10% Prepayment Option Chosen.

(a) Once, each calendar year, ("Year"), the Borrower may, provided that an Event of Default has not occurred, prepay in one lump sum, an amount of principal outstanding under a Fixed Rate Term Loan not exceeding 10% of the original amount of the Fixed Rate Term Loan, upon payment of all interest accrued to the date of prepayment without paying any prepayment charge. If the prepayment privilege is not used in one Year, it cannot be carried forward and used in a later Year.

(b) Provided that an Event of Default has not occurred, the Borrower may prepay more than 10% of the original amount of a Fixed Rate Term Loan in any Year, upon payment of all interest accrued to the date of prepayment and an amount equal to the greater of:

i) three months' interest on the amount of the prepayment (the amount of prepayment is the amount of prepayment exceeding the 10% limit described in Section 4(a)) using the interest rate applicable to the Fixed Rate Term Loan being prepaid; and

ii) the Yield Maintenance, being the difference between:

a. the current outstanding principal balance of the Fixed Rate Term Loan; and
b. the sum of the present values as of the date of the prepayment of the future payments to be made on the Fixed Rate Term Loan until the last day of the Rate Term, plus the present value of the principal amount of the Fixed Rate Term Loan that would have been due on the maturity

of the Rate Term, when discounted at the Government of Canada bond yield rate with a term which has the closest maturity to the unexpired term of the Fixed Rate Term Loan.

10% Prepayment Option Not Chosen.

(c) The Borrower may, provided that an Event of Default has not occurred, prepay all or any part of the principal then outstanding under a Fixed Rate Term Loan upon payment of all interest accrued to the date of prepayment and an amount equal to the greater of:

i) three months' interest on the amount of the prepayment using the interest rate applicable to the Fixed Rate Term Loan being prepaid; and

ii) the Yield Maintenance, being the difference between:

a. the current outstanding principal balance of the Fixed Rate Term Loan; and
b. the sum of the present values as of the date of the prepayment of the future payments to be made on the Fixed Rate Term Loan until the last day of the Rate Term, plus the present value of the principal amount of the Fixed Rate Term Loan that would have been due on the maturity of the Rate Term, when discounted at the Government of Canada bond yield rate with a term which has the closest maturity to the unexpired term of the Fixed Rate Term Loan.

Floating Rate Term Loans

The Borrower may prepay the whole or any part of the principal outstanding under a Floating Rate Term Loan, at any time without the payment of prepayment charges.

5. STANDARD DISBURSEMENT CONDITIONS

The obligation of the Bank to permit any drawdowns hereunder at any time is subject to the following conditions precedent:

a) The Bank shall have received the following documents which shall be in form and substance satisfactory to the Bank:

i) A copy of a duly executed resolution of the Board of Directors of the Borrower empowering the Borrower to enter into this Agreement;
ii) A copy of any necessary government approvals authorizing the Borrower to enter into this Agreement;
iii) All of the Bank Security and supporting resolutions and solicitors' letter of opinion required hereunder;
iv) The Borrower's compliance certificate certifying compliance with all terms and conditions hereunder;
v) All operation of account documentation; and
vi) For drawdowns under the Facility by way of L/C or L/G, the Bank's standard form Letter of Credit Indemnity Agreement

b) The representations and warranties contained in this Agreement are correct.
c) No event has occurred and is continuing which constitutes an Event of Default or would constitute an Event of Default, but for the requirement that notice be given or time elapse or both.
d) The Bank has received the arrangement fee payable hereunder (if any) and the Borrower has paid all legal and other expenses incurred by the Bank in connection with the Agreement or the Bank Security.

6. STANDARD REPRESENTATIONS AND WARRANTIES

The Borrower hereby represents and warrants, which representations and warranties shall be deemed to be continually repeated so long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, that:

a) The Borrower is a duly incorporated corporation, a limited partnership, partnership, or sole proprietorship, duly organized, validly existing and in good standing under the laws of the jurisdiction where the Branch/Centre is located and each other jurisdiction where the Borrower has property or assets or carries on business and the Borrower has adequate corporate power and authority to carry on its business, own property, borrow monies and enter into agreements therefore, execute and deliver the Agreement, the Bank Security, and documents required hereunder, and observe and perform the terms and provisions of this Agreement.

b) There are no laws, statutes or regulations applicable to or binding upon the Borrower and no provisions in its charter documents or in any by-laws, resolutions, contracts, agreements, or arrangements which would be contravened, breached, violated as a result of the execution, delivery, performance, observance, of any terms of this Agreement.

c) No Event of Default has occurred nor has any event occurred which, with the passage of time or the giving of notice, would constitute an Event of Default under this Agreement or which would constitute a default under any other agreement.

d) There are no actions, suits or proceedings, including appeals or applications for review, or any knowledge of pending actions, suits, or proceedings against the Borrower and its subsidiaries, before any court or administrative agency which would result in any material adverse change in the property, assets, financial condition, business or operations of the Borrower.

e) All material authorizations, approvals, consents, licenses, exemptions, filings, registrations and other requirements of governmental, judicial and public bodies and authorities required to carry on its business have been or will be obtained or effected and are or will be in full force and effect.

f) The financial statements and forecasts delivered to the Bank fairly present the present financial position of the Borrower, and have been prepared by the Borrower and its auditors in accordance with the International Financial Reporting Standards or GAAP for Private Enterprises.

g) All of the remittances required to be made by the Borrower to the federal government and all provincial and municipal governments have been made, are currently up to date and there are no outstanding arrears. Without limiting the foregoing, all employee source deductions (including income taxes, Employment Insurance and Canada Pension Plan), sales taxes (both provincial and federal), corporate income taxes, corporate capital taxes, payroll taxes and workers' compensation dues are currently paid and up to date.

h) If the Bank Security includes a charge on real property, the Borrower or Guarantor, as applicable, is the legal and beneficial owner of the real property with good and marketable title in fee simple thereto, free from all easements, rights-of-way, agreements, restrictions, mortgages, liens, executions and other encumbrances, save and except for those approved by the Bank in writing.

i) All information that the Borrower has provided to the Bank is accurate and complete respecting, where applicable:

   i) the names of the Borrower's directors and the names and addresses of the Borrower's beneficial owners;
   ii) the names and addresses of the Borrower's trustees, known beneficiaries and/or settlors; and
   iii) the Borrower's ownership, control and structure.

7. STANDARD POSITIVE COVENANTS

So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower will, and will ensure that its subsidiaries and each of the Guarantors will:

a) Pay all amounts of principal, interest and fees on the dates, times and place specified herein, under the Rate and Payment Terms Notice, and under any other agreement between the Bank and the Borrower.

b) Advise the Bank of any change in the amount and the terms of any credit arrangement made with other lenders or any action taken by another lender to recover amounts outstanding with such other lender.

c) Advise promptly after the happening of any event which will result in a material adverse change in the financial condition, business, operations, or prospects of the Borrower or the occurrence of any Event of Default or default under this Agreement or under any other agreement for borrowed money.

d) Do all things necessary to maintain in good standing its corporate existence and preserve and keep all material agreements, rights, franchises, licenses, operations, contracts or other arrangements in full force and effect.

e) Take all necessary actions to ensure that the Bank Security and its obligations hereunder will rank ahead of all other indebtedness of and all other security granted by the Borrower.

f) Pay all taxes, assessments and government charges unless such taxes, assessments, or charges are being contested in good faith and appropriate reserves shall be made with funds set aside in a separate trust fund.

g) Provide the Bank with information and financial data as it may request from time to time, including, without limitation, such updated information and/or additional supporting information as the Bank may require with respect to any or all the matters in the Borrower's representation and warranty in Section 6(i).

h) Maintain property, plant and equipment in good repair and working condition.

i) Inform the Bank of any actual or probable litigation and furnish the Bank with copies of details of any litigation or other proceedings, which might affect the financial condition, business, operations, or prospects of the Borrower.

j) Provide such additional security and documentation as may be required from time to time by the Bank or its solicitors.

k) Continue to carry on the business currently being carried on by the Borrower its subsidiaries and each of the Guarantors at the date hereof.

l) Maintain adequate insurance on all of its assets, undertakings, and business risks.

m) Permit the Bank or its authorized representatives full and reasonable access to its premises, business, financial and computer records and allow the duplication or extraction of pertinent information therefrom.

n) Comply with all applicable laws.

8. STANDARD NEGATIVE COVENANTS

So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower will not and will ensure that its subsidiaries and each of the Guarantors will not:

a) Create, incur, assume, or suffer to exist, any mortgage, deed of trust, pledge, lien, security interest, assignment, charge, or encumbrance (including without limitation, any conditional sale, or other title retention agreement, or finance lease) of any nature, upon or with respect to any of its assets or undertakings, now owned or hereafter acquired, except for those Permitted Liens, if any, set out in the Letter.

b) Create, incur, assume or suffer to exist any other indebtedness for borrowed money (except for indebtedness resulting from Permitted Liens, if any) or guarantee or act as surety or agree to indemnify the debts of any other Person.

c) Merge or consolidate with any other Person, or acquire all or substantially all of the shares, assets or business of any other Person.

d) Sell, lease, assign, transfer, convey or otherwise dispose of any of its now owned or hereafter acquired assets (including, without limitation, shares of stock and indebtedness of subsidiaries, receivables and leasehold interests), except for inventory disposed of in the ordinary course of business.

e) Terminate or enter into a surrender of any lease of any property mortgaged under the Bank Security.

f) Cease to carry on the business currently being carried on by each of the Borrower, its subsidiaries, and the Guarantors at the date hereof.

g) Permit any change of ownership or change in the capital structure of the Borrower.

9. ENVIRONMENTAL

The Borrower represents and warrants (which representation and warranty shall continue throughout the term of this Agreement) that the business of the Borrower, its subsidiaries and each of the Guarantors is being operated in compliance with applicable laws and regulations respecting the discharge, omission, spill or disposal of any hazardous materials and that any and all enforcement actions in respect thereto have been clearly conveyed to the Bank.

The Borrower shall, at the request of the Bank from time to time, and at the Borrower's expense, obtain and provide to the Bank an environmental audit or inspection report of the property from auditors or inspectors acceptable to the Bank.

The Borrower hereby indemnifies the Bank, its officers, directors, employees, agents and shareholders, and agrees to hold each of them harmless from all loss, claims, damages and expenses (including legal and audit expenses) which may be suffered or incurred in connection with the indebtedness under this Agreement or in connection with the Bank Security.

10. STANDARD EVENTS OF DEFAULT

The Bank may accelerate the payment of principal and interest under any committed credit facility hereunder and cancel any undrawn portion of any committed credit facility hereunder, at any time after the occurrence of any one of the following Events of Default:

a) Non-payment of principal outstanding under this Agreement when due or non-payment of interest or fees outstanding under this Agreement within 3 Business Days of when due.

b) If any representation, warranty or statement made hereunder or made in connection with the execution and delivery of this Agreement or the Bank Security is false or misleading at any time.

c) If any representation or warranty made or information provided by the Guarantor to the Bank from time to time, including without limitation, under or in connection with the Personal Financial Statement and Privacy Agreement provided by the Guarantor, is false or misleading at any time.

d) If there is a breach or non-performance or non-observance of any term or condition of this Agreement or the Bank Security and, if such default is capable to being remedied, the default continues unremedied for 5 Business Days after the occurrence.

e) If the Borrower, any one of its subsidiaries, or, if any of the Guarantors makes a general assignment for the benefit of creditors, files or presents a petition, makes a proposal or commits any act of bankruptcy, or if any action is taken for the winding up, liquidation or the appointment of a liquidator, trustee in bankruptcy, custodian, curator, sequestrator, receiver or any other officer with similar powers or if a judgment or order shall be entered by any court approving a petition for reorganization, arrangement or composition of or in respect of the Borrower, any of its subsidiaries, or any of the Guarantors or if the Borrower, any of its subsidiaries, or any of the Guarantors is insolvent or declared bankrupt.

f) If there exists a voluntary or involuntary suspension of business of the Borrower, any of its subsidiaries, or any of the Guarantors.

g) If action is taken by an encumbrancer against the Borrower, any of its subsidiaries, or any of the Guarantors to take possession of property or enforce proceedings against any assets.

h) If any final judgment for the payment of monies is made against the Borrower, any of its subsidiaries, or any of the Guarantors and it is not discharged within 30 days from the imposition of such judgment.

i) If there exists an event, the effect of which with lapse of time or the giving of notice, will constitute an event of default or a default under any other agreement for borrowed money in excess of the Cross Default Threshold entered into by the Borrower, any of its subsidiaries, or any of the Guarantors.

j) If the Borrower, any one of its subsidiaries, or any of the Guarantors default under any other present or future agreement with the Bank or any of the Bank's subsidiaries, including without limitation, any other loan agreement, forward foreign exchange transactions, interest rate and currency and/or commodity swaps.

k) If the Bank Security is not enforceable or if any party to the Bank Security shall dispute or deny any liability or any of its obligations under the Bank Security, or if any Guarantor terminates a guarantee in respect of future advances.

l) If, in the Bank's determination, a material adverse change occurs in the financial condition, business operations or prospects of the Borrower, any of the Borrower's subsidiaries, or any of the Guarantors.

m) If the Borrower or a Guarantor is an individual, the Borrower or such Guarantor dies or is found by a court to be incapable of managing his or her affairs.

11. ACCELERATION

If the Bank accelerates the payment of principal and interest hereunder, the Borrower shall immediately pay to the Bank all amounts outstanding hereunder, including without limitation, the amount of unmatured B/As, CDOR and LIBOR Loans and the amount of all drawn and undrawn L/Gs and L/Cs. All cost to the Bank of unwinding CDOR and LIBOR Loans and all loss suffered by the Bank in re-employing amounts repaid will be paid by the Borrower.

The Bank may demand the payment of principal and interest under the Operating Loan, Agriculture Operating Line or Farm Property Line of Credit (and any other uncommitted facility) hereunder and cancel any undrawn portion of the Operating Loan, Agriculture Operating Line or Farm Property Line of Credit (and any other uncommitted facility) hereunder, at any time whether or not an Event of Default has occurred.

12. INDEMNITY

The Borrower agrees to indemnify the Bank from and against any and all claims, losses and liabilities arising or resulting from this Agreement. USD loans must be repaid with USD and CAD loans must be repaid with CAD and the Borrower shall indemnify the Bank for any loss suffered by the Bank if USD loans are repaid with CAD or vice versa, whether such payment is made pursuant to an order of a court or otherwise. In no event will the Bank be liable to the Borrower for any direct, indirect or consequential damages arising in connection with this Agreement.

13. TAXATION ON PAYMENTS

All payments made by the Borrower to the Bank will be made free and clear of all present and future taxes (excluding the Bank's income taxes), withholdings or deductions of whatever nature. If these taxes, withholdings or deductions are required by applicable law and are made, the Borrower, shall, as a separate and independent obligation, pay to the Bank all additional amounts as shall fully indemnify the Bank from any such taxes, withholdings or deductions.

14. REPRESENTATION

No representation or warranty or other statement made by the Bank concerning any of the Facilities shall be binding on the Bank unless made by it in writing as a specific amendment to this Agreement.

15. CHANGING THE AGREEMENT

a) The Bank may, from time to time, unilaterally change the provisions of this Agreement where (i) the provisions of the Agreement relate to the Operating Loan, Agriculture Operating Line or Farm Property Line of Credit (and any other uncommitted facility) or (ii) such change is for the benefit of the Borrower, or made at the Borrower's request, including without limitation, decreases to fees or interest payable hereunder or (iii) where such change makes compliance with this Agreement less onerous to the Borrower, including without limitation, release of security. These changes can be made by the Bank providing written notice to the Borrower of such changes in the form of a specific waiver or a document constituting an amending agreement. The Borrower is not required to execute such waiver or amending agreement, unless the Bank requests the Borrower to sign such waiver or amending agreement. A change in the Prime Rate and USBR is not an amendment to the terms of this Agreement that requires notification to be provided to the Borrower.

b) Changes to the Agreement, other than as described in a) above, including changes to covenants and fees payable by the Borrower, are required to be agreed to by the Bank and the Borrower in writing, by the Bank and the Borrower each signing an amending agreement.

c) The Bank is not required to notify a Guarantor of any change in the Agreement, including any increase in the Credit Limit.

16. ADDED COST

If the introduction of or any change in any present or future law, regulation, treaty, official or unofficial directive, or regulatory requirement, (whether or not having the force of law) or in the interpretation or application thereof, relates to:

i) the imposition or exemption of taxation of payments due to the Bank or on reserves or deemed reserves in respect of the undrawn portion of any Facility or loan made available hereunder; or,

ii) any reserve, special deposit, regulatory or similar requirement against assets, deposits, or loans or other acquisition of funds for loans by the Bank; or,

iii) the amount of capital required or expected to be maintained by the Bank as a result of the existence of the advances or the commitment made hereunder;

and the result of such occurrence is, in the sole determination of the Bank, to increase the cost of the Bank or to reduce the income received or receivable by the Bank hereunder, the Borrower shall, on demand by the Bank, pay to the Bank that amount which the Bank estimates will compensate it for such additional cost or reduction in income and the Bank's estimate shall be conclusive, absent manifest error.

17. EXPENSES

The Borrower shall pay, within 5 Business Days following notification, all fees and expenses (including but not limited to all legal fees) incurred by the Bank in connection with the preparation, registration and ongoing administration of this Agreement and the Bank Security and with the enforcement of the Bank's rights and remedies under this Agreement and the Bank Security whether or not any amounts are advanced under the Agreement. These fees and expenses shall include, but not be limited, to all outside counsel fees and expenses and all in-house legal fees and expenses, if in-house counsel are used, and all outside professional advisory fees and expenses. The Borrower shall pay interest on unpaid amounts due pursuant to this paragraph at the All-In Rate plus 2% per annum.

Without limiting the generality of Section 25, the Bank or the Bank's agent, is authorized to debit any of the Borrower's accounts with the amount of the fees and expenses owed by the Borrower hereunder, including the registration fee in connection with the Bank Security, even if that debiting creates an overdraft in any such account. If there are insufficient funds in the Borrower's accounts to reimburse the Bank or it's agent for payment of the fees and expenses owed by the Borrower hereunder, the amount debited to the Borrower's accounts shall be deemed to be a Prime Based Loan under the Operating Loan, the Agriculture Operating Line or Farm Property Line of Credit.

The Borrower will, if requested by the Bank, sign a Pre-Authorized Payment Authorization in a format acceptable to the Bank to permit the Bank's agent to debit the Borrower's accounts as contemplated in this Section.

18. NON WAIVER

Any failure by the Bank to object to or take action with respect to a breach of this Agreement or any Bank Security or upon the occurrence of an Event of Default shall not constitute a waiver of the Bank's right to take action at a later date on that breach. No course of conduct by the Bank will give rise to any reasonable expectation which is in any way inconsistent with the terms and conditions of this Agreement and the Bank Security or the Bank's rights thereunder.

19. EVIDENCE OF INDEBTEDNESS

The Bank shall record on its records the amount of all loans made hereunder, payments made in respect thereto, and all other amounts becoming due to the Bank under this Agreement. The Bank's records constitute, in the absence of manifest error, conclusive evidence of the indebtedness of the Borrower to the Bank pursuant to this Agreement.

The Borrower will sign the Bank's standard form Letter of Credit Indemnity Agreement for all L/Cs and L/Gs issued by the Bank.

With respect to chattel mortgages taken as Bank Security, this Agreement is the Promissory Note referred to in same chattel mortgage, and the indebtedness incurred hereunder is the true indebtedness secured by the chattel mortgage.

20. ENTIRE AGREEMENTS

This Agreement replaces any previous letter agreements dealing specifically with terms and conditions of the credit facilities described in the Letter. Agreements relating to other credit facilities made available by the Bank continue to apply for those other credit facilities. This Agreement, and if applicable, the Letter of Credit Indemnity Agreement, are the entire agreements relating to the Facilities described in this Agreement.

21. NON-MERGER

Notwithstanding the execution, delivery or registration of the Bank Security and notwithstanding any advances made pursuant thereto, this Agreement shall continue to be valid, binding and enforceable and shall not merge as a result thereof. Any default under this Agreement shall constitute concurrent default under the Bank Security. Any default under the Bank Security shall constitute concurrent default under this Agreement. In the event of an inconsistency between the terms of this Agreement and the terms of the Bank Security, the terms of this Agreement shall prevail and the inclusion of any term in the Bank Security that is not dealt with in this Agreement shall not be an inconsistency.

22. ASSIGNMENT

The Bank may assign or grant participation in all or part of this Agreement or in any loan made hereunder without notice to and without the Borrower's consent.

The Borrower may not assign or transfer all or any part of its rights or obligations under this Agreement.

23. RELEASE OF INFORMATION

The Borrower hereby irrevocably authorizes and directs the Borrower's accountant, (the "Accountant") to deliver all financial statements and other financial information concerning the Borrower to the Bank and agrees that the Bank and the Accountant may communicate directly with each other.

24. FX CLOSE OUT

The Borrower hereby acknowledges and agrees that in the event any of the following occur: (i) Default by the Borrower under any forward foreign exchange contract ("FX Contract"); (ii) Default by the Borrower in payment of monies owing by it to anyone, including the Bank; (iii) Default in the performance of any other obligation of the Borrower under any agreement to which it is subject; or (iv) the Borrower is adjudged to be or voluntarily becomes bankrupt or insolvent or admits in writing to its inability to pay its debts as they come due or has a receiver appointed over its assets, the Bank shall be entitled without advance notice to the Borrower to close out and terminate all of the outstanding FX Contracts entered into hereunder, using normal commercial practices employed by the Bank, to determine the gain or loss for each terminated FX contract. The Bank shall then be entitled to calculate a net termination value for all of the terminated FX Contracts which shall be the net sum of all the losses and gains arising from the termination of the FX Contracts which net sum shall be the "Close Out Value" of the terminated FX Contracts. The Borrower acknowledges that it shall be required to forthwith pay any positive Close Out Value owing to the Bank and the Bank shall be required to pay any negative Close Out Value owing to the Borrower, subject to any rights of set-off to which the Bank is entitled or subject.

25. SET-OFF

In addition to and not in limitation of any rights now or hereafter granted under applicable law, the Bank may at any time and from time to time without notice to the Borrower or any other Person, any notice being expressly waived by the Borrower, set-off and compensate and apply any and all deposits, general or special, time or demand, provisional or final, matured or unmatured, in any currency, and any other indebtedness or amount payable by the Bank (irrespective of the place of payment or booking office of the obligation), to or for the credit of or for the Borrower's account, including without limitation, any amount owed by the Bank to the Borrower under any FX Contract or other treasury or derivative product, against and on account of the indebtedness and liability under this Agreement notwithstanding that any of them are contingent or unmatured or in a different currency than the indebtedness and liability under this Agreement.

When applying a deposit or other obligation in a different currency than the indebtedness and liability under this Agreement to the indebtedness and liability under this Agreement, the Bank will convert the deposit or other obligation to the currency of the indebtedness and liability under this Agreement using the exchange rate determined by the Bank at the time of the conversion.

26. SEVERABILITY
In the event any one or more of the provisions of this Agreement shall for any reason, including under any applicable statute or rule of law, be held to be invalid, illegal or unenforceable, that part will be severed from this Agreement and will not affect the enforceability of the remaining provisions of this Agreement, which shall remain in full force and effect.

27. MISCELLANEOUS

i) The Borrower has received a signed copy of this Agreement;

ii) If more than one Person, firm or corporation signs this Agreement as the Borrower, each party is jointly and severally liable hereunder, and the Bank may require payment of all amounts payable under this Agreement from any one of them, or a portion from each, but the Bank is released from any of its obligations by performing that obligation to any one of them;

iii) Accounting terms will (to the extent not defined in this Agreement) be interpreted in accordance with accounting principles established from time to time by the Canadian Institute of Chartered Accountants (or any successor) consistently applied, and all financial statements and information provided to the Bank will be prepared in accordance with those principles;

iv) This Agreement is governed by the law of the Province or Territory where the Branch/Centre is located;

v) Unless stated otherwise, all amounts referred to herein are in Canadian dollars

28. DEFINITIONS
Capitalized Terms used in this Agreement shall have the following meanings:

"All-In Rate" means the greater of the interest rate that the Borrower pays for Floating Rate Loans or the highest fixed rate paid for Fixed Rate Term Loans.

"Agreement" means the agreement between the Bank and the Borrower set out in the Letter and this Schedule "A" - Standard Terms and Conditions.

"Business Day" means any day (other than a Saturday or Sunday) that the Branch/Centre is open for business.

"Branch/Centre" means The Toronto-Dominion Bank branch or banking centre noted on the first page of the Letter, or such other branch or centre as may from time to time be designated by the Bank.

"Contractual Term Maturity Date" means the last day of the Contractual Term period. If the Letter does not set out a specific Contractual Term period but rather refers to a period of time up to which the Contractual Term Maturity Date can occur, the Bank and the Borrower must agree on a Contractual Term Maturity Date before first drawdown, which Contractual Term Maturity Date will be set out in the Rate and Payments Terms Notice.

"Cross Default Threshold" means the cross default threshold set out in the Letter. If no such cross default threshold is set out in the Letter it will be deemed to be zero.

"Face Amount" means, in respect of:

(i) a B/A, the amount payable to the holder thereof on its maturity;

(ii) A L/C or L/G, the maximum amount payable to the beneficiary specified therein or any other Person to whom payments may be required to be made pursuant to such L/C or L/G.

"Fixed Rate Term Loan" means any drawdown in Canadian dollars under a Facility at an interest rate which is fixed for a Rate Term at such rate as is determined by the Bank at its sole discretion.

"Floating Rate Loan" means any loan drawn down, converted or extended under a Facility at an interest rate which is referenced to a variable rate of interest, such as the Prime Rate.

"Inventory Value" means, at any time of determination, the total value (based on the lower of cost or market) of the Borrower's inventories that are subject to the Bank Security (other than (i) those inventories supplied by trade creditors who at that time have not been fully paid and would have a right to repossess all or part of such inventories if the Borrower were then either bankrupt or in receivership, (ii) those inventories comprising work in process and (iii) those inventories that the Bank may from time to time designate in its sole discretion) minus the total amount of any claims, liens or encumbrances on those inventories having or purporting to have priority over the Bank.

"Letter" means the letter from the Bank to the Borrower to which this Schedule "A" - Standard Terms and Conditions is attached.

"Letter of Credit" or *"L/C"* means a documentary letter of credit or similar instrument in form and substance satisfactory to the Bank.

"Letter of Guarantee" or *"L/G"* means a stand-by letter of guarantee or similar instrument in form and substance satisfactory to the Bank.

"Maturity Date" for a Facility, means the date on which all amounts outstanding under such Facility are due and payable to the Bank.

"Person" includes any individual, sole proprietorship, corporation, partnership, joint venture, trust, unincorporated association, association, institution, entity, party, or government (whether national, federal, provincial, state, municipal, city, county, or otherwise and including any instrumentality, division, agency, body, or department thereof).

"Purchase Money Security Interest" means a security interest on an asset which is granted to a lender or to the seller of such asset in order to secure the purchase price of such asset or a loan incurred to acquire such asset, provided that the amount secured by the security interest does not exceed the cost of the asset and provided that the Borrower provides written notice to the Bank prior to the creation of the security interest, and the creditor under the security interest has, if requested by the Bank, entered into an inter-creditor agreement with the Bank, in a format acceptable to the Bank.

"Rate Term" means that period of time as selected by the Borrower from the options offered to it by the Bank, during which a Fixed Rate Term Loan will bear a particular interest rate. If no Rate Term is selected, the Borrower will be deemed to have selected a Rate Term of 1 year.

"Rate and Payment Terms Notice" means the written notice sent by the Bank to the Borrower setting out the interest rate and payment terms for a particular drawdown.

"Receivable Value" means, at any time of determination, the total value of those of the Borrower's trade accounts receivable that are subject to the Bank Security other than (i) those accounts then outstanding for 90 days, (ii) those accounts owing by Persons, firms or corporations affiliated with the Borrower, (iii) those accounts that the Bank may from time to time designate in its sole discretion, (iv) those accounts subject to any claim, liens, or encumbrance having or purporting to have priority over the Bank, (v) those accounts which are subject to a claim of set-off by the obligor under such account, MINUS the total amount of all claims, liens, or encumbrances on those receivables having or purporting to have priority over the Bank.

"Receivables/Inventory Summary" means a summary of the Borrower's trade account receivables and inventories, in form as the Bank may require and certified by a senior officer/representative of the Borrower.

"US$" or "USD Equivalent" means, on any date, the equivalent amount in United States Dollars after giving effect to a conversion of a specified amount of Canadian Dollars to United States Dollars at the exchange rate determined by the Bank at the time of the conversion.

Appendix 4 – TD Loan Agreement Operating Line Capital

TD Commercial Banking

Northern Ontario Commercial Banking Group
240 Main Street East
North Bay, Ontario
P1B 1B1

Telephone No.: (705) 495 6715
Fax No.: (705) 474 6297

May 28, 2020

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION
74 Commerce Court
North Bay, ON
P1B 8Y5

Attention: Mrs. Melissa Casson

Dear Mrs. Casson,

The following amending agreement (the "Amending Agreement") amends the terms and conditions of the credit facilities (the "Facilities") provided to the Borrower pursuant to the Agreement dated September 19, 2019.

BORROWER

PREVIOUS

NORTH BAY (ESPANOLA) ACQUISITION INC. (the "Borrower")

NEW

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION (the "Borrower")

LENDER

The Toronto-Dominion Bank (the "Bank"), through its Northern Ontario Commerical Banking Group in North Bay, Ontario.

CREDIT LIMIT

PREVIOUS

3) CAD $500,000

NEW

3) CAD $750,000

4) CAD$1,650,000

TYPE OF CREDIT AND BORROWING OPTIONS

4) **Committed Reducing Term Facility (Multiple Draw)** available at the Borrower's option by way of:
- Fixed Rate Term Loan in CAD$
- Floating Rate Term Loan available by way of:
  - Bankers Acceptances in CAD$ ("B/As")

PURPOSE

4) To finance annual capital spending requirements.

TENOR

4) Committed

CONTRACTUAL TERM

4) Up to 60 month(s) from the date of drawdown

RATE TERM (FIXED RATE TERM LOAN)

4) Fixed rate: 6 month, 12-60 months but never to exceed the Contractual Term Maturity Date
Floating rate: No term

AMORTIZATION

4) Up to 360 month(s)

INTEREST RATES AND FEES

Advances shall bear interest and fees as follows:

4) **Committed Revolving Facility:**
- Fixed Rate Term Loans: as determined by the Bank, in its sole discretion, for the Rate Term selected by the Borrower, and as set out in the Rate and Payment Terms Notice applicable to that Fixed Rate Term Loan.
- Floating Rate Term Loans available by way of:
  - B/As: as set out by the Bank, in its sole discretion, for the Rate Term selected by the Borrower, and as set out in the Swap Confirmation applicable to that Loan.

For all Facilities, interest payments will be made in accordance with Schedule "A" unless otherwise stated in this Letter or in the Rate and Payment Terms Notice applicable for a particular drawdown. Information on interest rate and fee definitions, interest rate calculations and payment is set out in the Schedule "A".

DRAWDOWN

Assigned Facilities	Description
4)	B/A borrowings are restricted to maturities of 30 days minimum and 120 days maximum. BA stamping fees are calculated and payable on an issuance basis, based on a 365/366 day year. Borrower is to provide a minimum 3 business days notice prior to intention to borrow via BAs.
4)	Multiple draws permitted up to the credit limit. Minimum drawdown of $100,000 for Fixed Rate loans and $1,000,000 for B/A based loans. Final drawdown to be completed by December 31, 2022, after which any amount not drawn is cancelled. All draw requests are to be accompanied by a Drawdown Certificate, executed by one of Borrower's senior officers, confirming compliance with all Bank and OEB covenants and conditions pre and post drawdown on a consolidated basis with guarantor.

Each drawdown under 4 will be a "tranche" and each tranche will bear its own interest rate and repayment terms as set out in the Rate and Payment Terms Notice delivered by the Bank to the Borrower in respect of that drawdown.

Notice periods, minimum amounts of draws, interest periods and contract maturity for LIBOR Loans, terms for Banker's Acceptances and other similar details are set out in the Schedule "A" attached hereto.

REPAYMENT AND REDUCTION OF AMOUNT OF CREDIT FACILITY

4) All amounts outstanding will be repaid on or before the Contractual Term Maturity Date. Multiple draws are permitted during the period ending December 31, 2022 commencing from the date of the Letter. Any amounts not drawn by such time will be cancelled. All drawdowns will be repaid in equal monthly payments. The details of repayment and interest rate applicable to such drawdown will be set out in the "Rate and Payment Terms Notice" applicable to that drawdown. Any amounts repaid may not be reborrowed.

Notwithstanding the foregoing, drawdowns by BA or LIBOR Loan will not be repaid in periodic instalments as set out above, but rather will be repaid at the end of the term of the BA or LIBOR Loan by the Borrower making another drawdown up to the amount of the Credit Limit as such Credit Limit is reduced using the amortization period set out herein.

PREPAYMENT

4) The Borrower has not selected the 10% Prepayment Option and accordingly, Fixed Rate Term Loans under this Facility may be prepaid in accordance with Section 4c) of Schedule A.

4) The Borrower has selected the 10% Prepayment Option and accordingly, Fixed Rate Term Loans under this Facility may be prepaid in accordance with Section 4a) and 4b) of Schedule A.

SECURITY

The following security shall be provided, shall, unless otherwise indicated, support all present and future indebtedness and liability of the Borrower and the grantor of the security to the Bank including without limitation indebtedness and liability under guarantees, foreign exchange contracts, cash management products, and derivative contracts, shall be registered in first position, and shall be on the Bank's standard form, supported by resolutions and solicitor's opinion, all acceptable to the Bank.

NEW

f) A resolution of the board of directors of the Borrower authorizing the borrowing of CAD $1,650,000 for facility #4.

g) A resolution of the board of directors of the Borrower authorizing the borrowing of CAD $750,000 for facility #3.

All persons and entities required to provide a guarantee shall be referred to in this Agreement individually as a "Surety" and/or "Guarantor" and collectively as the "Guarantors";

All of the above security and guarantees shall be referred to collectively in this Agreement as "Bank Security".

DISBURSEMENT CONDITIONS

The obligation of the Bank to permit any drawdown hereunder is subject to the Standard Disbursement Conditions contained in Schedule "A" and the following additional drawdown conditions:

Delivery to the Bank of the following, all of which must be satisfactory to the Bank:

3) A borrowing resolution and by-law authorizing an increase in the operating line from $500,000 to $750,000

4) A borrowing resolution and by-law authorizing the borrowing of up to $1,650,000.

4) If the 30 year amortization is chosen for Fac# 3, the LDC is to demonstrate to the Bank prior to drawdown:

   a. Municipal control over of the LDC's Board of Directors
   b. Municipal review of the LDC's financial statements
   c. Municipal review of budgets

AVAILABILITY OF OPERATING LOAN

The Operating Loan is uncommitted, made available at the Bank's discretion, and is not automatically available upon satisfaction of the terms and conditions, conditions precedent, or financial tests set out herein.

The occurrence of an Event of Default is not a precondition to the Bank's right to accelerate repayment and cancel the availability of the Operating Loan.

SCHEDULE "A" -
STANDARD TERMS
AND CONDITIONS

Schedule "A" sets out the Standard Terms and Conditions ("Standard Terms and Conditions") which apply to these credit facilities. The Standard Terms and Conditions, including the defined terms set out therein, form part of this Agreement, unless this letter states specifically that one or more of the Standard Terms and Conditions do not apply or are modified.

Unless otherwise stated, the amendments outlined above are in addition to the Terms and Conditions of the existing Agreement. All other terms and conditions remain unchanged.

We ask that the Borrower acknowledges agreement to these amendments by signing and returning the attached duplicate copy of this Amending Agreement to the undersigned on or before **June 30, 2020.**

ACCURACY OF
INFORMATION

The Borrower hereby represents and warrants that all information that it has provided to the Bank is accurate and complete respecting, where applicable:

(i) the names of the Borrower's directors and the names and addresses of the Borrower's beneficial owners;
(ii) the names and addresses of the Borrower's trustees, known beneficiaries and/or settlors; and
(iii) the Borrower's ownership, control and structure.

The Borrower will provide, or cause to be provided, such updated information and/or additional supporting information as the Bank may require from time to time with respect to any or all the matters in the Borrower's foregoing representation and warranty.

Yours truly,

THE TORONTO-DOMINION BANK

Jonathan Loewen	Andrew Crawford
Relationship Manager	Manager Commercial Credit

TO THE TORONTO-DOMINION BANK:

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION hereby accepts the foregoing offer this 4th day of JUNE, 2020. The Borrower confirms that, except as may be set out above, the credit facility(ies) detailed herein shall not be used by or on behalf of any third party.

Signature

MATT PAYNE, PRESIDENT & CEO
Print Name & Position

Signature

MELISSA CASSON, VP-FINANCE
Print Name & Position