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

BY E-MAIL

March 8, 2021

Christine E. Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: North Bay Hydro Distribution Limited (North Bay Hydro)
Application for 2021 Electricity Distribution Rates
OEB Staff Interrogatories
Ontario Energy Board File Number: EB-2020-0043

In accordance with Procedural Order No. 1, please find attached OEB staff's interrogatories in the above noted proceeding. North Bay Hydro and all intervenors have been copied on this filing.

North Bay Hydro's responses to interrogatories are due by March 30, 2021.

Yours truly,

Jerry Wang Digitally signed by Jerry Wang
Date: 2021.03.08
15:15:02 -05'00'

Jerry Wang
Advisor, Electricity Distribution: Major Rate Applications & Consolidations

Attach.

OEB Staff Interrogatories
North Bay Hydro Distribution Limited
2021 Cost of Service Application

Exhibit 1 – Administrative Documents

1-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.).

1-Staff-2
Responses to Letters of Comment

Following publication of the Notice of Application, the OEB received one letter 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 letter 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.

1-Staff-3
Management Compensation
Ref 1: Exhibit 1, Pages 48-49

North Bay Hydro indicated that it has a review of management compensation scheduled to be completed in 2021.

(a) Has the review been completed? If not, please indicate when North Bay Hydro expects the review to be completed.
(b) If the review is expected to be completed during the course of this proceeding, please provide a copy of the review when it is available.

1-Staff-4
Customer Surveys
Ref 1: Exhibit 1, Pages 83-94

North Bay Hydro engaged in two surveys with customers, a telephone survey and an online survey.

(a) Please provide a copy of the surveys with all of the questions asked and the responses.

1-Staff-5
Customer Service
Ref 1: Exhibit 1, Pages 76-77, 89

North Bay Hydro noted that it has an average of 10,000 customers go to its physical office annually and continues to see the need for in-person service options. On page 89, North Bay Hydro also noted that “customers have made clear their increasing preference for digital and self-service options.”

(a) Are more customers shifting towards using digital and self-serve options?
(b) Approximately how much customer service is done in-person versus through digital / self-service options?
(c) Has the COVID-19 pandemic accelerated the adoption of digital communication over in-person service options?

1-Staff-6
Paperless Billing
Ref 1: Exhibit 1, Page 89

North Bay Hydro's survey explored the idea of reducing costs through the use of self-serve and online/digital options.

(a) How much does North Bay Hydro expect to save through paperless billing?
(b) Has North Bay Hydro undertaken any steps towards moving more customers to paperless billing? If yes, are the cost savings reflected in North Bay Hydro's OM&A and are any incentive credits to customers recorded in other revenues? If no, why not?

1-Staff-7
Customer Survey
Ref 1: Exhibit 1, Pages 89-92

North Bay Hydro's survey probed customers on ideas to further empower customers (e.g. smartphone application, more self-serve options on the website).

(a) In presenting these ideas of greater self-serve/online functionality, did North Bay Hydro also indicate to customers the capital investments that would be required and the potential bill impacts?

1-Staff-8
DSP Implementation
Ref 1: Exhibit 1, Page 108

North Bay Hydro measures its DSP implementation progress by comparing its actual gross capital spending to its budgeted gross capital spending in any given year with the goal of at least meeting the spending envelope detailed in the DSP.

(a) How does North Bay Hydro ensure that more progress is actually being made, rather than just more costs being incurred? (i.e. wouldn't overspending in any particular project also increase the DSP implementation progress metric?)
(b) Does North Bay Hydro currently track the amount of planned completion versus actual completion of any key units (transformers, poles, etc.) on an annual basis? If no, why not?

1-Staff-9
Return on Equity
Ref 1: Exhibit 1, Page 112

North Bay Hydro earned modestly above its 9.3% deemed ROE in 2018, but significantly under-earned in 2019 and was below 3% of the deemed ROE.

(a) Please explain all the factors for the underearning in 2019.
(b) Please calculate the 2019 ROE if costs associated with the 2019 purchase of Espanola Regional Hydro Distribution Corporation are removed.

1-Staff-10
Incentive Pay
Ref 1: Exhibit 1, Page 118

Page 118 indicates that more achievement points are given to North Bay Hydro's management team the more the budget is spent.

(a) Please explain if these achievement measures only measure the amount of capital that is spent each year, or if it is also tied towards the percentage of project completion budgeted in any given year.
(b) What incentive measures does North Bay Hydro have that are tied to distribution system performance?

Exhibit 2 – Rate Base

2-Staff-11
COVID-19 Impacts

Please explain if North Bay Hydro's capital plans and budgets as presented include forecasted impacts due to COVID-19.

2-Staff-12
Microgrid Project
Ref 1: Exhibit 2, Page 40
Ref 2: DSP, Page 41

As noted on page 40, MS23 was constructed because it was required to service a community microgrid. North Bay Hydro also undertook generation connection activities for the microgrid.

(a) Please provide more details on the microgrid including its scale and intended function.
(b) Was this microgrid constructed at the initiative of North Bay Hydro, or some other entity?
(c) Are the microgrid assets owned and operated by North Bay Hydro, or some other entity? If owned by North Bay Hydro, what was the total capital cost of the project?
(d) Did North Bay Hydro receive capital contributions for this work in accordance with section 3.2 of the Distribution System Code? If yes, please provide the calculations of the amounts received. If no, why not?

From reference 2, OEB staff notes that North Bay Hydro has spare capacity in many of its distribution substations.

(e) Please explain why a new substation was required for the microgrid project.

2-Staff-13
Working Capital Allowance
Ref 1: Exhibit 2, Page 45

North Bay Hydro continues to use calendar month billing, which provides benefits to North Bay Hydro.

(a) What benefits does North Bay Hydro gain from using calendar month billing?

2-Staff-14
Cost of Power
Ref 1: Chapter 2 Appendices, App.2-ZA and App.2-ZB

The following are the forecasted commodity prices North Bay 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		$20.87	$20.87
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$109.47	$109.47
Adjustments ($/MWh)				$3.24
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$133.58**

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 and adjustments are unchanged, but the GA $/MWh is now $83.62.

(a) Please update appendices 2-ZA, 2-ZB and North Bay Hydro’s cost of power calculations.
(b) Please update North Bay Hydro’s working capital allowance calculations.

2-Staff-15
SAIDI/SAIFI
Ref 1: DSP, Pages 20-24

Defective equipment and foreign interference are among the top contributors to interruptions, excluding loss of supply and major event days.

(a) If available, please provide a table showing the historical number of customer interruptions under defective equipment broken down into asset classes and a table for customer hours of interruptions. As well, please provide a table showing the SAIDI contribution per asset class and a table showing the SAIFI contribution per asset class.
(b) What are the main contributors to foreign interference interruptions? What steps has North Bay Hydro taken to mitigate these types of interruptions?

2-Staff-16
Voltage Conversion
Ref 1: Exhibit 2, Pages 67-68

Appendix 2-AA is reproduced in the reference noted above. OEB staff notes a large number of voltage conversion projects under the system renewal category. Under system service, there appears to be only one item for voltage conversion, “18F3 Voltage Conversion,” with total past spending of less than $100k.

(a) Please explain why these projects were considered system renewal projects, rather than system service.
(b) With North Bay Hydro's voltage conversion efforts mostly completed, please explain why there is no significant decrease in North Bay Hydro's forecasted system renewal spending.

2-Staff-17
O&M Savings
Ref 1: DSP, Pages 9-10, 90
Ref 2: Exhibit 2, Page 55 (Appendix 2-AB)

In reference 1, North Bay Hydro noted a number of anticipated cost savings, among which are system O&M savings. One noted example is underground renewal, which is expected to reduce O&M costs associated with underground outage restoration costs.

However, in Appendix 2-AB, OEB staff notes that North Bay Hydro's system O&M is increasing significantly in the test year and continues to increase by inflation over the period of the DSP.

(a) Where have North Bay Hydro's cost savings been reflected? Please explain any impact anticipated cost savings have had on North Bay Hydro's budgets.
(b) Given the anticipated cost savings, please explain why system O&M continues to increase. In particular, on page 90 of the DSP, North Bay Hydro noted that O&M costs are inversely correlated with declining asset condition and therefore expect a reduction in future O&M costs. Despite North Bay Hydro's continued system renewal spending, there is no decrease in the forecasted system O&M costs.

2-Staff-18
System Renewal
Ref 1: DSP, Page 63
Ref 2: Chapter 2 Appendices, Appendix 2-AB

North Bay Hydro indicated on page 63 of the DSP that the test year has a higher than usual number of composite pole installations planned. OEB staff notes that the test year capital budget is higher than every other year in the forecast period.

(a) Please explain why it is necessary to accelerate the installation of composite poles specifically in the test year. Has North Bay Hydro considered spreading out the installation of composite poles across the period of the DSP to better smooth out its capital spending and rates?

(b) What are the projected reliability improvements (SAIDI, SAIFI, or CAIDI) associated with the acceleration the installation of composite poles?

2-Staff-19
Asset Replacement Plan
Ref 1: DSP, Page 64

North Bay Hydro's Asset Replacement Plan recommends a total of 127 poles for replacement in 2021-2023 and 135 from 2024-2025. Specifically for the test year, North Bay Hydro has planned to replace 129 poles.

(a) Please clarify that, where the reference says "a total of 127 poles… and 135", these replacements numbers are intended to be annual numbers.
(b) Over the historical period 2015-2020, on average, how many poles has North Bay Hydro replaced annually?

2-Staff-20
Project Prioritization
Ref 1: DSP, Pages 70-76, 92

As indicated in the reference, North Bay Hydro uses a weighted prioritization criteria to prioritize its capital plans. A table with North Bay Hydro's planned test year projects and associated priority ranking is shown on page 92.

(a) At what point does North Bay Hydro determine that a project must be completed within a certain year? That is to say, is there a threshold of project scores under which projects will be deferred to the next rate year?
(b) As an example, project "WF0551260 – Montrose Ave Rebuild" has one of the lowest priority rankings in the table on page 92. Would this project be able to be deferred to 2022?
(c) North Bay Hydro's test year system renewal budget is significantly higher than the rest of the forecasted years. Has North Bay Hydro considered deferring some of its low priority projects to later years in order to smooth out its capital spending?

2-Staff-21
Asset Condition Assessment
Ref 1: Asset Condition Assessment (ACA), Pages 31-35

In total, North Bay Hydro owns approximately 10,384 distribution poles, but only 5,955 poles carrying primary circuit were considered in the ACA.

(a) What are the other poles that are not currently included in the condition assessment? Why were these poles not included?
(b) Please confirm that North Bay Hydro's proposed pole renewal plans only target poor condition poles within the population of 5,955 poles. What are North Bay Hydro's renewal plans for the remainder of the pole population not included in the condition assessment?

The ACA noted that only 31% of the distribution of wood poles have a valid health index. The remaining 69% of poles have an extrapolated health index.

(c) The 31% of poles that is referred to in the ACA, is this referring to the population of 5,955 poles or the entire pole population of 10,384?
(d) The ACA notes that North Bay Hydro visits and inspects all poles in 3-year cycles. What are the missing data that prevents the calculation of a valid health index for 69% of the poles?

OEB staff notes that less than 50% of North Bay Hydro's pole population have a valid health index – the majority of poles have an extrapolated health index. Sub-transmission poles have a similar issue with the lack of data availability.

(e) Please discuss the validity of using the health indices of poles as an input for pole renewal planning when most poles do not have a valid health index.
(f) What efforts is North Bay Hydro taking to improve its data availability issues for poles?

2-Staff-22
Fleet Renewal
Ref 1: DSP, Page 76

North Bay Hydro has a fleet replacement schedule that was created in 2015 based on the fleet assessment completed in 2013.

(a) Please provide a copy of the fleet replacement schedule.
(b) Does North Bay Hydro strictly replace its fleet according to this schedule, or does North Bay Hydro continue to track the condition of vehicles in its fleet and vary the replacement schedule as necessary?

2-Staff-23
General Plant
Ref 1: Chapter 2 Appendices, Appendix 2-AA

OEB staff notes that North Bay Hydro’s test year spending on software at $158,150 is significantly higher than historical years.

(a) Please provide a breakdown of the different software that make up this amount.
(b) Please discuss the need to complete all of these software upgrades in the test year.

2-Staff-24
System Renewal
Ref 1: DSP, Appendix I, Project A, Transformers – System Renewal

The table in the sixth bullet shows that North Bay Hydro’s test year spending ($229,240) in this program is approximately equal to average of North Bay Hydro’s historical expenditures for this program. This section further notes that a significant number of transformers were required and installed in the past few years due to voltage conversion projects.

(a) OEB staff notes that North Bay Hydro’s voltage conversion projects have mostly been completed. In light of this, please explain why North Bay Hydro has forecasted the test year budget at historical average levels if less transformers (i.e. for voltage conversion) will be required.

2-Staff-25
System Renewal
Ref 1: DSP, Appendix I, Project B, WF0551387 – MacBeth Cres – Capital Project

The project description of this project discusses cost sharing with Bell, with Bell providing the costs of the poles.

(a) OEB staff understanding is that this is an overhead to underground conversion project, with overhead assets being replaced with underground. Please clarify Bell's role in this project. What poles are being replaced?
(b) If North Bay Hydro removes these poles and moves everything underground, where will Bell put its assets?
(c) Does North Bay Hydro expect any capital contribution from Bell? If yes, please indicate how much it is, and why the capital contributions noted for this project is $0.

2-Staff-26
System Renewal
Ref 1: DSP, Appendix I, Project C, WF0525291 – Walalce Rd – Sub-Transmission Line Rebuild (44kV)

This line rebuild project affects Hydro One Networks Inc. as the line in question also carries Hydro One Networks circuits and equipment.

(a) Please clarify whether these pole lines are owned by North Bay Hydro or Hydro One Networks Inc.
(b) Given that the line rebuild must be designed to accommodate Hydro One Networks Inc.'s 44 kV circuit as well, does North Bay Hydro expect any capital contribution from Hydro One Networks Inc. for this project? If yes, what is the amount expected, and why is the capital contributions shown as $0? If no, why not?
(c) North Bay Hydro noted that it must coordinate with Hydro One Networks Inc. to coordinate the isolation and de-energizing of the line, which poses a risk to the timeline of the project. Please provide an update to the status of this project and whether it is still expected to be completed in 2021.

2-Staff-27
System Renewal
Ref 1: DSP, Appendix I, Project K, MS15 Rehabilitation

OEB staff notes that the scope of this project pertains to the engineering design work of anticipated rehabilitation work at MS15 with actual construction expected to start in 2022 and be put in-service in 2022.

(a) Please explain why North Bay Hydro has listed this as a separate project, instead of including it with the construction costs, to be completed in 2022. What will be used and useful when the engineering portion is completed in 2021, but not the physical construction?

(b) Please clarify if these costs are included in the 2021 capital additions.

2-Staff-28
System Renewal
Ref 1: DSP, Appendix I, Project L, MS18 – MS18 Rehabilitation (Engineering)

Under comparative information, North Bay Hydro stated the historical costs of rehabilitating MS11 for comparison purposes.

(a) How many reclosers and relays were replaced for the MS11 rehabilitation project?

2-Staff-29
System Access
Ref 1: DSP, Appendix I, Projects N, O, P, Q, R
Ref 2: Appendix 2-AA

The projects in the reference all refer to system access projects. OEB staff notes that, for each of the projects, the amount of capital contributions indicated is $0.

(a) Please explain why North Bay Hydro has not included any capital contributions for these system access projects.
(b) Please explain what the contributed capital line item in Appendix 2-AA for the test year represents and also explain how North Bay Hydro calculated this number.
(c) Please provide a breakdown of the contributed capital line item in Appendix 2-AA into the projects each amount relates to.

2-Staff-30
System Access
Ref 1: DSP, Appendix I, Project R, Road Relocations

(a) To date, is North Bay Hydro aware of any road relocation projects from the municipality scheduled to be completed in 2021?

2-Staff-31
General Plant
Ref 1: DSP, Appendix I, Project S, Yard Fabric Structure

There are several benefits listed for this project, many of which relate to O&M, such as eliminating the time required to clear snow from vehicles and equipment, making equipment more accessible during the winter, and reducing the risk of equipment freezing to cement pads.

(a) Are these O&M savings reflected in North Bay Hydro’s O&M and reliability metrics (SAIDI, SAIFI, CAIDI) forecasts? If yes, please indicate the quantum of savings. If no, why not?

2-Staff-32
General Plant
Ref 1: DSP, Appendix I, Project T, General Building Work
Ref 2: Building Assessment Report, Appendix F Table, Building Assessment Recommendations 2021-2025, Page 2

North Bay Hydro’s proposed test year spending on general building work is $130,300. In reference 2, there is a table provided as part of the Building Assessment Report summarizing the capital spending needs over 2021-2025 on the building. OEB staff notes that the “needs” budget as laid on in reference 2 has $62,900 in spending for the test year, with the total 2021-2025 cost of $219,900 spread out across the five years. It appears that North Bay Hydro has opted for a different budget, with $130,300 in the test year, and then $22,400 in subsequent years.

(a) Please explain why North Bay Hydro has opted not to follow the timing and schedule as recommended by the Building Assessment Report. In particular, please explain why it is necessary to budget more than half of the total work in the test year.

2-Staff-33
Fleet Renewal
Ref 1: DSP, Appendix I, Project V, Replacement of Truck 34
Ref 2: Chapter 2 Appendices, Appendix 2-AB

The project description noted that the finished unit (Truck 34) will be delivered and put into service in Q2 2022 with a total cost of $464,143. The 2021 costs of $119,649 are only related to the cab and chassis components.

(a) Please explain why North Bay Hydro has included this project in the test year when it appears the finished unit will not be put in-service until 2022. What will be used and useful in 2021 if the finished unit will not be delivered until 2022?
(b) Do North Bay Hydro's 2021 capital additions include the 2021 costs?

Under project alternatives, one alternative considered was replacing the truck in 2022 instead of 2021, which North Bay Hydro stated would double truck replacement costs in 2022. OEB staff notes that North Bay Hydro's 2021 test year net capex exceeds the 2022 forecasted net capex by over $800k.

(c) Please discuss why North Bay Hydro opted not to defer this project to 2022, which could help smooth out North Bay Hydro's total capex over the DSP period.

2-Staff-34
Fleet Renewal
Ref 1: DSP, Appendix I, Project W, Replacement of Truck 43

The project description noted that the finished unit (Truck 43) will be delivered and put into service in Q2 2021 with a total cost of $323,941. The 2021 costs of $214,084 are only related to the aerial life / bucket components.

(a) Please explain why North Bay Hydro has split the costs of this truck between 2020 and 2021 when it appears the finished unit will not be put in-service until 2021.
(b) Do North Bay Hydro's 2020 capital additions include the 2020 costs?

Under project timing, North Bay Hydro noted that the cab and chassis of the truck were scheduled to be delivered in Q4 2020. North Bay Hydro goes on to note potential delays caused by COVID-19

(c) Has North Bay Hydro received the cab and chassis? If yes, when?
(d) How certain is North Bay Hydro that it will receive the full and finished unit before the end of 2021?

Exhibit 3 – Operating Revenue

3-Staff-35
Load Forecast
Ref 1: Exhibit 3, Pages 8-9, 25-33
Ref 2: Load Forecast Model, sheet: Summary

North Bay Hydro has selected a five-year historic period for regression due to a low R-Square and worsening in other measures of predictive capability when longer time periods were tested.

OEB staff notes that billed energy decreased every year from 566,701,778 kWh in 2010 to 482,398,546 kWh in 2017 with the largest decreases between 2014 and 2016. In 2018, energy use increased to 496,980,971 kWh.

The regression model used Heating Degree Days, Cooling Degree Days, Number of Days in the Month, and a Spring Fall Flag.

In explaining year over year variances from 2015, North Bay Hydro explained that “the average usage per customer will be a reflection of weather, economic indicators, and the result of local CDM efforts.”

(a) Is North Bay Hydro aware of any reasons for the decrease in load from 2010 to 2017? In particular, the larger reductions between 2014 and 2016?
(b) Has North Bay Hydro attempted to address the historic reductions in load through dummy variables, economic variables, or other measures? If so, please explain what has been attempted.
(c) Please produce a scenario with ten years of data where a dummy variable is included that indicates 1 in every month from January 2010 to June 2015, and then zero in every month from July 2015 to December 2021.
(d) Has North Bay Hydro attempted to address the impact of economic indicators or local CDM efforts in its load forecast? If so, what were the results, if not, why not?

3-Staff-36
Load Forecast
Ref 1: Bay Today, "City's financial contribution to natural gas expansion project formalized", January 28, 2021.

Bay Today reports that an agreement has been reach which will bring natural gas service to Peninsula and Northshore Roads.

(a) Does North Bay Hydro expect to lose load due to fuel conversions away from electricity?
(b) If the answer to a) is yes, does it have an estimate of the timing of these conversions, and the amounts of load it expects to lose?

3-Staff-37
Load Forecast
Ref 1: Exhibit 3, Page 34
Ref 2: Load Forecast Model, sheet: Rate Class Energy Model

North Bay Hydro notes that "When determining the billed energy forecast as described in 2.3.3.3, NBHDL applied a 3-year geometric mean year over year in 2020 and 2021 to determine the non-normalized average consumption by class with the same average 10-year average heating and cooling degree days."

OEB staff notes that ten years of growth rate data is available, and five years of data were used in the regression equations.

(a) Please explain why the three-year geometric mean was selected, and not either a five-year or ten-year geometric mean, consistent with either the period used for regression, or the available data.
(b) As a scenario, please provide a load forecast, where a five-year geometric mean growth rate is applied to 2020 and 2021.

3-Staff-38
CDM Savings
Ref 1: Exhibit 3, Page 17, Table 3-15
Ref 2: Participation and Cost (P&C) Report

North Bay Hydro included actual conservation and demand management (CDM) savings results up to and including 2019 in its load forecast. An extract of Table 3-15 is shown below.

	2018	2019	2020	2021
2018 CDM Programs	4,027,457	2,917,353	2,907,174	2,907,174
2019 CDM Programs		1,827,951	1,946,094	2,199,926

(a) Please explain what project savings are included in 2018 (4,027,457 kWh) and 2019 (1,827,951 kWh) in Table 3-15.
   i. Please confirm that any additional savings, that are not reflected in the P&C Report, were approved by the IESO to be delivered as part of the Conservation First Framework.

(b) Please explain why there is an increase in savings from 2019 programs into the 2021 test year from 1,827,951 kWh (2019), 1,946,094 kWh (2020) to 2,199,926 kWh (2021).

(c) Please confirm whether the 2021 impact from 2019 CDM programs (2,199,926 kWh) represents a full year of 2019 programs. If not, please reflect the full-year of 2019 actual amounts in the load forecast.

(d) Please file the supporting documentation (for example, an aggregated version of CDM-IS excel report) to reconcile the 2021 CDM savings included from prior year programs in the load forecast. In the excel spreadsheet, please ensure the following details are included:
   - Framework under which the savings will be delivered under (e.g. CFF wind-down framework, interim framework, etc.)
   - Date that the program was approved by the IESO
   - Expected completion date of the program
   - Expected kWh and kW savings (net)
   - Delivery agent for the program savings (e.g. LDC or IESO led)
   - Approval date of an IESO incentive

3-Staff-39
CDM Adjustments
Ref 1: Exhibit 3, Page 18, Table 3-16

In Table 3-16, North Bay Hydro included a CDM manual adjustment of 2,644,686 kWh to its 2021 load forecast based on savings from a cogeneration project. OEB staff labelled the breakdown of these adjustments as “Adjustment 1” and “Adjustment 2”.

CDM adjustment – 2021	**kWh**	
2021 Manual adjustment	1,099,963	Starting number
Less CEP	-777,539	Adjustment 1
NBHDL CEP Adj	2,322,262	Adjustment 2
Total Manual Adjustment	2,644,686	

For Adjustment 2, North Bay Hydro notes it is “based on 70% of the former usage of the customers at this location without a loss in kW as the facility is expected to continue to peak normally based on periodic shut downs at the generation facility.”

(a) Please confirm the in-service date(s) of the cogeneration project(s), whose forecast savings are included in the CDM adjustment.
(b) Please explain what the starting 2021 manual adjustment of 1,099,963 kWh represents and what this value is based on, including reference source(s) of the data and key assumptions used in the estimate.
(c) Please explain what the CEP adjustment reflects, as this first adjustment results in a deduction of 777,539 kWh from the 2021 load.
(d) Please provide the facility peak value(s) that were used in estimating forecast savings of 2,322,262 kWh, including the reference source(s) of base consumption (i.e. peaks based on periodic shutdowns) and how the facility peak(s) were selected.
    i. Please confirm that the 70% allocation of former usage reflects a 30% reduction of load due to periodic shutdowns and is based on facility-specific measurements. If not, please explain how the 70% estimate was derived.
    ii. Please show the calculation of the 2,322,262 kWh savings figure.

3-Staff-40
Other Revenues
Ref 1: Exhibit 3, Page 36, Table 3-44

OEB staff notes that the other revenues variance table shown in the reference above is missing account 4362 – Loss on Disposition of Utility Property. Please provide a revised variance table with account 4362 as well as an explanation for any material past variances.

3-Staff-41
Other Revenues
Ref 1: Chapter 2 Appendices, Appendix 2-H
Ref 2: Revenue Requirement Workform, Tab 3. Data_Input_Sheet

OEB staff is unable to reconcile the “Other Revenue” inputs in the RRWF to Appendix 2-H.

(a) Please reconcile the different specific service charges amounts shown in the two references ($144,519 in Appendix 2-H but $111,570 in the RRWF).
(b) Please provide a breakdown of the “Other Distribution Revenues” and “Other Income and Deductions” items in the RRWF and reconcile it with Appendix 2-H.

Exhibit 4 – Operating Expenses

4-Staff-42
COVID-19 Impacts

Please explain if North Bay Hydro’s OM&A budget and forecasted expenses, aside from North Bay Hydro’s forecast of bad debts, include forecasted impacts due to COVID-19.

4-Staff-43
Employees
Ref 1: Exhibit 4, Page 9

North Bay Hydro created a new operations coordinator role in the operations department to complement the operations manager and operations supervisor.

(a) Please provide further details on the responsibilities of the operations coordinator and how the role will fit in with the existing manager and supervisor roles.

North Bay Hydro indicated that its operations manager and supervisor are expected to retire in the near future.

(b) When are these two employees expected to retire?

4-Staff-44
OM&A
Ref 1: Exhibit 4, Page 12
Ref 2: Exhibit 1, Page 91

The test year includes costs towards the creation of a secure mobile app for customers.

(a) Are there incremental OM&A costs associated with the mobile app? If yes, what are the costs and in OM&A program are these costs recorded?
(b) In the second reference, North Bay Hydro discusses customer preferences for the mobile app among the 18-34 years old demographic and among commercial customers. Please provide the overall customer preferences (i.e. across all age groups) related to the mobile app.

4-Staff-45
OM&A
Ref 1: Exhibit 4, Pages 12-13, 26
Ref 2: Exhibit 1, Pages 121-122

North Bay Hydro forecasted $150k annually towards “corporate policies, initiatives, and strategy.”

OEB staff notes that $110k was already spent in this category in 2020.

(a) Please indicate if this was the actual amount spent or a forecast at the time of filing. If forecast, please provide the actual amount spent in 2020.
(b) Please provide a breakdown of the costs incurred.
(c) Please provide a breakdown of what costs are expected to be incurred in 2021 (e.g. the external consultants that North Bay Hydro expects to contract).
(d) Please provide further details on the need for continual annual spending in this category. What initiatives does North Bay Hydro have planned for 2022-2025, and what of these initiatives cannot be completed by North Bay Hydro’s executive team and employees?

North Bay Hydro expects to merge with Espanola Regional Hydro Distribution Corporation in 2022.

(e) Please explain why it is preferable to engage in these initiatives now, such as a comprehensive update of North Bay Hydro’s Conditions of Service, instead of waiting until after the merger, when these initiatives can be applied to the merged utility?

4-Staff-46
Regulatory Costs
Ref 1: Exhibit 4, Pages 13-14, 78
Ref 2: Exhibit 1, Pages 121-122

North Bay Hydro's actual 2015 regulatory costs were over $200k more than forecast ($920,898 vs. $656,930). North Bay Hydro's total forecasted costs for this cost of service application is $793,550.

(a) Why were the 2015 actual regulatory costs higher than forecast?
(b) How much has North Bay Hydro spent to date for this cost of service application?

As noted in reference 2, North Bay Hydro intends to enter a five-year deferred rebasing period after merging with Espanola Regional Hydro Distribution Corporation in 2022.

(c) Given the deferred rebasing period, North Bay Hydro would not rebase until 2027, which is six years from 2021. Has North Bay Hydro considered amortizing its regulatory costs over six years instead of five to reflect the fact that it does not expect to rebase until 2027? If North Bay Hydro does not support amortization over six years, please explain why not.

4-Staff-47
Employees
Ref 1: Exhibit 4, Page 55

North Bay Hydro is currently recruiting for a substation electrician learner.

(a) Has North Bay Hydro filled this position?
(b) What other positions are currently included in North Bay Hydro's FTE forecast, but remain vacant and still need to be filled? When does North Bay Hydro expect to fill these positions?

4-Staff-48
Customer Engagement
Ref 1: Exhibit 4, Pages 14, 77-78
Ref 2: Chapter 2 Appendices, Appendix 2-JC

On page 77 under regulatory costs, North Bay Hydro has included $71,300 for customer engagement and consultation related to this cost of service application. In table 4-6 on page 14, the amortized costs of this application are included in North Bay Hydro's 2021 total regulatory costs of $270,679. OEB staff notes that this corresponds to the "Regulatory Reporting & Assessments" item in Appendix 2-JC.

In Appendix 2-JC, there is another separate line item for customer engagement with test year costs of $164,820.

(a) Please explain what customer engagement costs are included as part of regulatory costs, and what costs are included under the "customer engagement" line item.
(b) Please confirm that no customer engagement costs have been double counted in both accounts.

4-Staff-49
Customer Engagement
Ref 1: Exhibit 4, Pages 36-37
Ref 2: Chapter 2 Appendices, Appendix 2-JC

The responsibilities of the new communications officer role include dealing with customer engagement. North Bay Hydro explained that part of the increase to "Executive, Financial, Regulator, Professional, Insurance" in Appendix 2-JC is due to the addition of the new communications officer. There is a separate line item in Appendix 2-JC for customer engagement.

(a) Please explain what costs are recorded under the Customer Engagement budgets versus what costs are recorded under "Executive, Financial, Regulator, Professional, Insurance" as part of the costs of the new communications officer.

On pages 36-37, North Bay Hydro noted that the hiring of a communications officer is a cost-effective solution because it no longer needs to rely on affiliate resources and could additionally outsource the communications officer to its affiliates.

(b) Please provide a breakdown of the impact of adding a communications officer on North Bay Hydro's budgets, i.e. the incremental cost of the new FTE against the revenue offset of not using affiliate resources as well as outsourcing the employee to affiliates.

4-Staff-50
OM&A
Ref 1: Exhibit 4, Page 24

North Bay Hydro has determined that the allocation ratio between OM&A and capital should change from what was used in its 2015 rebasing application to better reflect the time spent on O&M. For line crews, this is 43% to O&M and for engineering this is 53% to O&M.

(a) Please explain how North Bay Hydro calculated the 43% for lines and 53% for engineering allocation ratios.

4-Staff-51
OM&A
Ref 1: Exhibit 4, Page 25
Ref 2: Chapter 2 Appendices, Appendix 2-JC

For the bridge and test years, North Bay Hydro has forecasted $200k annually in bad debt expenses.

(a) Please explain how North Bay Hydro derived its forecast of $200k.
(b) What are North Bay Hydro's actual bad debt expenses in 2020?

4-Staff-52
Maintenance Programs
Ref 1: Exhibit 4, Pages 28-29

Starting in the 2021 test year, North Bay Hydro is starting several maintenance programs consisting of wood pole testing, underground cable testing and an ARC flash study.

(a) Please explain how North Bay Hydro estimated the annual costs of these programs.

(b) Has North Bay Hydro ever conducted an ARC flash study in the past? Please explain the reasoning for completing this study in the test year.
(c) Please explain if the ARC flash study is a one-time cost or an annual cost of $110k.

4-Staff-53
Vegetation Management
Ref 1: Exhibit 4, Pages 29-30, 76

North Bay Hydro's 2015 vegetation management budget was $456,194 to complete tree trimming under a four-year cycle. Starting in the test year, North Bay Hydro is proposing an annual budget of $773,437 to complete tree trimming under a five-year cycle.

North Bay Hydro explained that it has historically struggled to complete its vegetation management due to lack of contractor availability, pricing volatility, poor contractor performance, and contractor crew constraints that led to work not being completed.

To address these issues, North Bay Hydro along with two other utilities found a solution through the formation of 17 Trees.

(a) Please explain the corporate relationship between North Bay Hydro and 17 Trees. How did North Bay Hydro help form this company?
(b) OEB staff notes that work contracted to 17 Trees is sole sourced. How does North Bay Hydro ensure that the prices from 17 Trees are competitive?

As described by North Bay Hydro, it is OEB staff's understanding that 17 Trees addresses the issues noted above, namely price volatility and contractor availability.

(c) Given that 17 Trees is expected to provide better service, and North Bay Hydro's tree trimming cycle is being increased from a four-year cycle as budgeted in 2015 to a five-year cycle in 2021 (i.e. less work each year), please explain why an increase to the vegetation management budget is required.
(d) Please explain how North Bay Hydro determined that a five-year cycle would be the optimal vegetation management strategy in balancing costs, resourcing and system reliability.

4-Staff-54
Employee Compensation
Ref 1: Exhibit 4, Page 101

As noted in the reference, an external consultant regularly reviews North Bay Hydro's compensation plan for competitiveness against two market comparators.

(a) When was North Bay Hydro's compensation plan last reviewed?
(b) Please provide the previous review(s) that was conducted of North Bay Hydro's compensation plan.

4-Staff-55
Employee Compensation
Ref 1: Exhibit 4, Pages 57-58
Ref 2: Chapter 2 Appendices, Appendix 2-K

OEB staff notes large year over year increases in total compensation to management from 2015 actuals to 2018 actuals. However, as described on pages 57-58, there does not seem to be any material change to North Bay Hydro's management during that period, and Appendix 2-K indicates that the management FTE count did not change during that period.

(a) Please explain the reasons for the increases in management compensation.

4-Staff-56
Affiliates
Ref 1: Exhibit 4, Page 70, Table 4-31

For the test year, there are $465,612 in affiliate revenues shown in Table 4-31 that are used as a direct reduction in North Bay Hydro's test year OM&A.

(a) Please map the OM&A reductions shown in table 4-31 to the OM&A programs in Appendix 2-JC that they are recorded in.

4-Staff-57
Employee Compensation
Ref 1: Exhibit 4, Page 58

For benchmarking purposes, North Bay Hydro participates in and reviews the MEARIE Management Salary Survey of Local Distribution Companies.

(a) Please provide the results for North Bay Hydro in the most recent survey.
(b) Has North Bay Hydro taken any steps in response to the results from the benchmarking surveys?

4-Staff-58
PILs
Ref 1: Exhibit 4, Page 101

North Bay Hydro assumed a loss carry-forward of $2,048,903 in its originally filed application.

(a) If available, please provide an update for 2020 actuals and update the PILs model/RRWF as necessary.

4-Staff-59
LRAMVA
Ref 1: Exhibit 4, Appendix 4-F, IndECO report, Page 11
Ref 2: Tab 2 of LRAMVA workform
Ref 3: EB-2014-0099, Settlement Proposal, June 22, 2015 (PDF page 46 of 49)

The forecast demand savings for the GS 50-2999 kW class is 8,959 kW in the LRAMVA workform, but it appears to be 33,344 kW from the settlement proposal.

2015 CDM Manual Adjustment	2015 (kWh) - Full Year	Factor	2015 CDM Adjustment
2014 CDM Programs	2,656,334	0.5	1,328,167
2015 CDM Programs Excl Cogen	1,343,022	0.5	671,511
2015 Cogen	12,200,000	0.25	3,050,000
Total	16,199,356		5,049,678

2015 LRAMVA Threshold	kWh	kW
Residential	1,769,698	
General Service < 50 kW	967,905	
General Service 50 to 2999 kW	13,461,754	33,344
Total	16,199,356	33,344

Source: EB-2014-0099, Settlement Proposal, June 22, 2015

In the IndECO report filed as Appendix 4-F, it noted the following on page 11:

> In the case of the demand threshold (kW), the value in the table in the settlement is not consistent with that actually used in the agreed upon load forecasting model. The load forecast for GS>50 rate class was increased (meaning the CDM impact was decreased) because the cogeneration facility developed in NBHDL's service territory was not expected to fully impact revenues to the extent of the anticipated energy savings. The 2015 forecast load was increased by 25% of 24,000 kW; 25% since the facility was only expected to begin operations in the final quarter of 2015. **This LRAMVA kW threshold value in the table of the agreement does not capture this adjustment. (emphasis added)**

(a) Please reconcile the 33,344 kW of forecast savings from the GS 50-2999 kW class in the settlement agreement to the 8,959 kW of forecast savings used for lost revenue calculations.
(b) Please clarify whether the 8,959 kW reflects an annualized savings value, and confirm the actual amount of savings that was embedded in the load forecast.
(c) If an annualized value is not used for LRAMVA purposes, please explain why the 8,959 kW figure is appropriate.

4-Staff-60
LRAMVA
Ref 1: LRAMVA workform, Tab 3-a and Tab 5

North Bay Hydro included Post-P&C report savings as part of its 2019 LRAMVA balance, which were not identified in the P&C report and completely reconciled in Tab 3-a of the LRAMVA workform.

(a) Please confirm that all Post-P&C savings are reflective of program savings approved as part of the former Conservation First Framework. Please discuss eligibility of the program savings.

4-Staff-61
LRAMVA
Ref 1: Tab 8 of LRAMVA workform
Ref 2: Exhibit 4, IndECO report, Pages 8-9

North Bay Hydro has included savings from two cogeneration related projects that participated in the IESO's Process and Upgrade Program as part of the LRAMVA.

For project 1 (North Bay Regional Health Centre), savings are calculated from the difference between billed demand and max load (billed + generated kW). Max load is used as the base case had the project not been in place. The pre- and post-demand are provided on a monthly basis.

For project 2 (Community Energy Park – microgrid comprised of solar panels, cogeneration and battery storage), savings are calculated from the difference between monthly billed demand and monthly shadow bills. A shadow bill was used as the facility is not interval metered.

(a) For project 1, please confirm that billed demand represents the point at which the facility was billed in the month.
(b) For project 2, please explain the approach to develop a shadow bill and provide a numerical example.
    i. How did North Bay Hydro ensure that the monthly facility usage developed in shadow bills is reflective of the base case, had the cogeneration project (reflected in Tab 8) not existed at the YMCA Aquatic Centre, Thomson Park and Memorial Gardens?
(c) For both projects, the data from June 2020 to April 2021 was estimated based on the average of Jan 2018 to May 2020 facility usage. Please discuss whether any actual data is now available to recalculate the CHP savings. If yes, please recalculate the lost revenues for both projects for the months that have actual data available in Tab 8 of the LRAMVA workform, and quantify the impact of the LRAMVA balance.
(d) If there are no changes to part c), please confirm whether the average of Jan 2018 to May 2020 is reflective of actual usage at both facilities, if the facilities may or may not have operated at full capacity during the COVID-period from June 2020-April 2021.

4-Staff-62
LRAMVA
Ref 1: LRAMVA workform

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

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

Exhibit 5 – Cost of Capital

N/A

Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency

6-Staff-63
Revenue Requirement
Ref 1: RRWF, Tab 10

OEB staff notes that cell D32 in tab 10 of the RRWF refers to the "GS>2000<5000" rate class.

(a) Please confirm that this is meant to refer to the GS 3000kW-4,999kW rate class.

Exhibit 7 – Cost Allocation

7-Staff-64
Cost Allocation
Ref 1: Exhibit 7, Pages 4-5
Ref 2: Cost Allocation Model, sheet I3 TB Data, sheet E4 TB Allocation Details

To determine the weighting factors for Billing and Collecting, an analysis of Accounts 5315 and 5320 was conducted. It is later explained that late payment revenue forms part of this analysis.

(b) Please provide the derivation of the billing and collecting weighting factors including the major cost drivers used, and USoA account for each cost driver.
(c) Please confirm that North Bay Hydro tracks late payment charge revenue in account 4225, or explain where it is tracked, and what is tracked in account 4225.
(d) Please confirm that Account 4225 – Late Payment Charges is not allocated using the billing and collecting weighting factor.

7-Staff-65
Cost Allocation
Ref 1: Cost Allocation Model, sheet I6.2 Customer Data, sheet I8 Demand Data

North Bay Hydro has forecasted 269 General Service 50 – 2,999 kW customers. Of these, it indicates that 242 rely on line transformers provided by North Bay Hydro. It also indicates that it provides secondary distribution service for 265 customers.

(a) For the 27 GS 50 – 2,999 kW customers where North Bay Hydro is not providing line transformer service, please confirm that the customer is providing its own line transformer or explain why this is not the case.
(b) If part a) can be confirmed, please explain the situation that would give rise to a providing its transformer, but North Bay Hydro owning the secondary assets on the low side of the transformer.

7-Staff-66
Rate Classifications
Ref 1: Exhibit 7, Page 8
Ref 2: Exhibit 1, Page 51

North Bay Hydro is proposing to amend the name of its “General Service 3,000 to 4,999 kW Service Classification” to “General Service Greater Than 3,000 kW.” OEB staff notes that North Bay Hydro’s current conditions of service, as linked in reference 2, continues to refer to “General Service (3001kW – 5000kW).”

(a) As noted in the Chapter 2 Filing Requirements, distributors are required to identify any changes to its Conditions of Service that would result from the approval of the application. Please confirm whether North Bay Hydro would update its Conditions of Service to reflect the name change noted above.

Exhibit 8 – Rate Design

8-Staff-67
Retail Transmission Service Rates
Ref 1: RTSR Model, sheet 4. UTRs and Sub-Transmission
Ref 2: EB-2020-0030, Decision and Rate Order, December 17, 2020
Ref 3: EB-2020-0251, Decision and Rate Order, December 17, 2020

North Bay Hydro has used the 2020 Hydro One Sub-Transmission rates and 2020 UTRs to calculate its proposed 2021 RTSR charges.

As noted in the second reference, the OEB has approved updated sub-transmission rates for Hydro One Networks Inc. As noted in the third reference, the OEB has approved updated 2021 UTRs.

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

8-Staff-68
Low Voltage Charges
Ref 1: Exhibit 8, Page 13
Ref 2: EB-2020-0030, Decision and Rate Order, December 17, 2020

North Bay Hydro has used Hydro One Networks Inc.'s 2020 low voltage rates to forecast its low voltage expense.

As noted in the second reference, the OEB has approved new distribution rates for Hydro One Networks Inc. effective January 1, 2021.

(a) Please update the low voltage forecast and recovery calculations using Hydro One Networks Inc.'s 2021 approved low voltage rates.

8-Staff-69
Cost Allocation
Ref 1: Revenue Requirement Work Form, sheet 13 Rate Design
Ref 2: Cost Allocation Model, sheet O2 Fixed Charge|Floor|Ceiling

North Bay Hydro is proposing to increase the fixed charge for GS 50 – 2,999 kW from $315.75 to $371.19, and the fixed charge for GS 3,000 – 4,999 kW from $6,734.18 to $7,673.78. Both of these fixed charges are already above the Minimum System with Peak Load Carrying Capability (PLCC) Adjustment from the cost allocation model.

(a) Please provide the variable charges that would result from keeping the fixed charge at the current charge for these two rate classes.

8-Staff-70
Retail Service Charges
Ref 1: Exhibit 8, pages 11-12
Ref 2: EB-2020-0285, Decision and Rate Order, December 3, 2020

North Bay Hydro has proposed a 2.0% inflation factor for its Retail Service Charges.

The OEB's generic retailer service charges for 2021 have been increased using an inflation factor of 2.2%.

(a) Does North Bay Hydro propose to use the generic retailer service charges, or the 2.0% inflation factor from Exhibit 8?
(b) If North Bay Hydro proposes to use the standard charges, please update the tariff of rates and charges.

8-Staff-71
Tariff and Bill Impact
Ref 1: Tariff and Bill Impact Model, sheet 6. Bill Impacts

North Bay Hydro's tariff and bill impact model currently uses an Ontario Electricity Rebate rate of 31.8%. Effective January 1, 2021, the Ontario Electricity Rebate has been reduced to 21.2%.

(a) OEB staff has revised North Bay Hydro's tariff and bill impact models to reflect the new 21.2% Ontario Electricity Rebate. The revised models are attached to these interrogatories – please use the revised models to make any updates to bill impacts going forward.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-72
DVAs
Ref 1: Exhibit 4, Page 104
Ref 2: Exhibit 9, Page 18

At the first above-noted reference, North Bay Hydro stated:

> NBHDL determined the amount in Account 1592 for 2019 by having its outside tax specialists determine income taxes with and without the use of accelerated CCA. For the 2019 historical period, this amount was determined to be $177,903.

At the second above-noted reference, North Bay Hydro presented Table 9 – 9: PILs and Tax Variance, which is reproduced below:

PILs and Tax Variance	**Total**	**50% Claim**
2019	177,903	88,952
Closing 2019 Interest	-	-
Projected Interest – April 30, 2021	2,784	1,392
Total Claim		**90,344**

(a) Please provide a detailed calculation on how the total $177,903 was determined.
(b) Please confirm if the above calculation is based on actual 2019 capital additions or capital additions approved in North Bay Hydro Distribution's last cost of service proceeding.
(c) If the calculation is based on actual 2019 capital additions, please provide the calculation using approved capital additions. If the calculation is based on approved capital additions, please provide the calculation based on actual 2019 capital additions.

9-Staff-73
Ref 1: Exhibit 9, Page 18

At the above-noted reference, North Bay Hydro stated:

> In the 2019 audited financial statements, and the subsequent RRR 2.1.7 NBHDL included 100% of the impact as directed by the OEB in the above excerpt. However, as part of this Application, NBHDL is requesting that it retain 50% of the tax incentive.

In its Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, July 25, 2019, the OEB stated that:

> For natural gas utilities and electricity distributors and transmitters, the OEB's long-standing practice with respect to the impact of changes in taxes due to regulatory or legislated tax changes during an incentive rate-setting period has been to share the impacts between Utility shareholders and ratepayers on a 50/50 basis1. However, Utilities should not expect that this practice will necessarily apply in respect of CCA rule changes, and determinations as to the appropriate disposition methodology will be made at the time of each Utility's cost-based application.

(a) Please explain why a 50/50 split between the Utility and rate payers of the benefits resulting from the temporary changes in CCA tax rules introduced by Bill C-97 is a fair and equitable method of disposing of these amounts.