1-Staff-1

Reference: Updated Revenue Requirement Work Form (RRWF) and Models

Question(s):

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

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2022 Electricity Distributor Rate Applications webpage.

Response:

BHI provides an updated RRWF in working Microsoft Excel format with any corrections or adjustments that it wishes to make to the amounts in the populated version of the RRWF filed in its initial Application. BHI also files an updated set of models that reflects the interrogatory responses. The RRWF and updated set of models are filed as follows:

- Attachment_OEB_Chapter2Appendices_BHI_07242025
- Attachment_OEB_ACM_ICM_Model_BHI_07242025
- Attachment_Load_Forecast_Model_BHI_07242025
- Attachment_RRWF_BHI_07242025
- Attachment_2026_PILS Workform_BHI_07242025
- Attachment_2026_Cost Allocation Model_BHI_07242025
- Attachment_OEB_RTSR_Workform_BHI_07242025
- Attachment_OEB_Tariff_Schedule_and_Bill_Impact_Model_BHI_07242025
- Attachment_DVA_Continuity_Schedule_BHI_07242025

BHI provides a summary of the changes in Appendix 1-Staff-1.

1-Staff-2

Reference: Letters of Comment

Question(s):

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

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

Response:

BHI filed a response to the matters raised in the letters of comment referenced above on July 24, 2025.

2-Staff-3

Reference:
System Access – Overspending in 2024 and 2025
Ref 1: Exhibit 2, pp. 117-118

Preamble:

From 2021 to 2025, actual System Access expenditures totaled $93.5 million, surpassing the budgeted $66.3 million by $27.3 million, or 41%. In 2024 and 2025, actuals exceeded the budget by 73% and 198%, respectively.

Question(s):

a) For the years 2024 and 2025, please provide the planned and actual costs (gross and net) for System Access for each of the variance explanations noted in Table 5.4-6 and 5.4-7.

b) Burlington Hydro stated that in 2024 and 2025 there were, "higher General Service expenditures driven by increased customer demand for new connections and upgrades."

   i) What specific customer segments drove the increased demand for new connections and upgrades?

   ii) How many new connections and upgrades were completed in 2024 and 2025 compared to forecast?

c) For the 2025 system access variance explanation, Burlington Hydro stated that higher true-up contribution payments by Burlington Hydro for the Tremaine TS Connection Cost Recovery Agreement as 100% of the forecasted load on the TS did not materialize, resulting in Burlington Hydro having to pay a higher capital contribution as mandated under the Transmission System Code.

   i) Please provide a copy of the CCRA agreement with Hydro One and the bill from Hydro One.

   ii) What was the load forecast in the CCRA agreement?

   iii) What load was realized at the Termaine TS?

   iv) Why was the realized load less than the forecast load?

   v) How did Burlington Hydro establish the original load forecast and has Burlington Hydro changed it's load forecasting for this application?

Response:

a) BHI provides the planned and actual costs (gross and net) for System Access for each of the variance explanations noted in Table 5.4-6 in the DSP for 2024 in Table 1 below.

Table 1

Category	2024			
	Plan		Actual	
	Gross	Net	Gross	Net
	$ '000			
Burlington TS Wholesale Metering	$0	$0	$1,003	$1,003
General Service	$2,800	$1,925	$5,181	$3,327
Smart Meter Replacement/Reverification	$0	$0	$406	$406
Other System Access	$5,274	$2,144	$11,145	$2,318
Total System Access	**$8,074**	**$4,069**	**$17,736**	**$7,054**
Variance actual net vs. plan net				**$2,985**

BHI updated its 2025 capital expenditure forecast in response to 1-Staff-1. It provides the planned and budget costs (gross and net) for System Access for each of the variance explanations noted in Table 5.4-7 in the DSP for 2025 capital expenditures on that basis, in Table 2 below.

Table 2

Category	2025			
	Plan		Budget	
	Gross	Net	Gross	Net
	$ '000			
Dundas St Road Widening - (Guelph line to Kerns Rd.)	$0	$0	$9,178	$4,781
General Service	$2,800	$1,925	$4,030	$3,155
Smart Meter Replacement/Reverification	$0	$0	$277	$277
Tremaine TS CCRA True-up	$0	$0	$63	$63
Other System Access	$5,274	$2,144	$12,547	$2,452
Total System Access	**$8,074**	**$4,069**	**$26,096**	**$10,729**
Variance budget net vs. plan net				**$6,660**

b)

i) The Residential and GS>50 customers segments primarily drove the increased demand for new connections and upgrades.

ii) BHI provides new connections and upgrades completed in 2024 and 2025 compared to forecast in Table 3 below.

Table 3

Description	2024	2025	2024 vs. Forecast	2025 vs. Forecast
New connections and upgrades completed	1,070	1,225	660	807

c)

i) BHI provides a copy of the original CCRA agreement, the amended agreement and the 10-year true-up bill for Tremaine TS CCRA with/from Hydro One as Appendix 2-Staff-3 c) i to these interrogatory responses.

ii) BHI provides the load forecast in the CCRA agreement, its realized load and updated load forecast for the 1st true-up (5-years) and the 2nd true-up (10-years) in Table 4 below. Please note that BHI has also included its realized load and updated load forecast in Table 4 to satisfy part iii) of this interrogatory response.

Table 4

Year	Load forecast CCRA agreement MW*	Load realized/ forecast 1st true-up 5-years MW*	1st true-up realized/ updated forecast	Load forecast/ realized 2nd true-up 10-years MW*	2nd true-up realized/ updated forecast
2013	32.6	17.0	Realized	17.0	Realized
2014	36.2	27.9	Realized	27.9	Realized
2015	39.9	31.0	Realized	31.0	Realized
2016	43.4	37.2	Realized	37.2	Realized
2017	47.1	34.5	Realized	34.5	Realized
2018	50.7	41.4	Updated forecast	37.6	Realized
2019	54.3	39.4	Updated forecast	27.5	Realized
2020	58	41.4	Updated forecast	42.4	Realized
2021	61.5	43.4	Updated forecast	42.2	Realized
2022	65.1	45.4	Updated forecast	45.0	Realized
2023	68.6	47.4	Updated forecast	50.3	Realized
2024	71.8	49.4	Updated forecast	52.3	Updated forecast
2025	74.7	51.5	Updated forecast	48.7	Updated forecast
2026	77.2	53.6	Updated forecast	52.9	Updated forecast
2027	79.4	55.7	Updated forecast	55.0	Updated forecast
2028	81	57.8	Updated forecast	57.1	Updated forecast
2029	82.2	60.0	Updated forecast	59.2	Updated forecast
2030	83.1	62.7	Updated forecast	61.9	Updated forecast
2031	83.9	65.4	Updated forecast	64.6	Updated forecast
2032	84.8	69.0	Updated forecast	68.1	Updated forecast
2033	85.6	72.4	Updated forecast	71.4	Updated forecast
2034	86.3	76.5	Updated forecast	75.3	Updated forecast
2035	87.2	81.2	Updated forecast	79.6	Updated forecast
2036	88	85.9	Updated forecast	83.4	Updated forecast
2037	88.8	86.4	Updated forecast	85.3	Updated forecast

**adjusted for peak load index*

iii) Please see BHI’s response in part (ii) above.

iv) The realized load was less than forecasted load primarily due to slower than expected new commercial and residential developments.

v) The original load forecast established by BHI was developed based on the historical distribution system coincidence peak load and available population growth forecasts from the City of Burlington and Region of Halton. As part of the Connection Cost Recovery Agreement BHI is obligated to review and update the load forecast every 5 years during the true up process. BHI’s Application reflects the updated forecast used for the 2nd true-up with Hydro One as identified in Table 4 above.

2-Staff-4

Reference:
Capital Contributions
Ref 1: Chapter 2 Appendices, Tab 2-AB

Preamble:
From 2021-2024 actuals and the 2025 bridge forecast show that capital contributions accounted for 65.1% of total capital expenditures for System Access. For the forecast period, capital contributions only accounts for 51.7% of total capital expenditures for the System Access.

Question(s):

a) Please explain the drivers for forecasting a lower amount of capital contributions for the forecast period in comparison to historical for System Access.

Response:

a) BHI updated its capital expenditures for 2025 and 2026 in response to Interrogatory 1-Staff-1 and therefore uses updated amounts in this response. Based on the updated forecast for 2025 and 2026, capital contributions are expected to account for 51.9% of total System Access capital expenditures during the forecast period (2026-2030), compared to 66.1% for the 2021–2024 actuals and 2025 bridge year. The key drivers for the lower percentage of capital contributions are outlined below:

   3rd Party Relocation Projects

   The Metrolinx GO Corridor Electrification Project was fully funded through capital contributions during the historical period and is not continuing into the forecast period. As identified in its response to 2-Intervenor-13 a), BHI received more than $25M in capital contributions from this project over the 2021-2025 period, which significantly impacted the amount of capital contributions as a percentage of gross capital expenditures compared to the forecast period.

   Similarly, the Burloak Grade Separation Project is almost entirely funded through capital contributions. BHI received almost $7M in capital contributions over the historical period, and this project is expected to be completed in 2026.

   Extended revenue and connection horizon for system expansions

   The updated DSC requirements have extended the revenue horizon and connection horizon for system expansions. As a result, BHI has forecasted lower capital contributions for expansion-related projects during the forecast period to account for this change.

2-Staff-5

Reference:
Smart Meters
Ref 1: Exhibit 2, DSP Appendix A: Material Investment Summary Documents, Smart Meter Replacement/Reverification
Ref 2: Chapter 2 Appendices, Tab 2-AA
Ref 3: Exhibit 1, PDF Part 1 of 2, pp. 105-106

Question(s):

a) Please explain how Burlington Hydro projected that 15% of its meter population will have failed by the end of 2025.

b) Over what time frame did Burlington Hydro initially roll out its smart meters?

c) Please provide the failure rate for smart meters for the last five years.

d) What did the manufacturer advise is the expected life of the smart meters?

e) Will Burlington Hydro use internal or external contracted resources to execute this program? If Burlington Hydro is using internal labour resources, have these resources already been hired and onboarded?

f) How will Burlington Hydro track and report on benefits such as improved billing accuracy, reduced outages, or customer engagement?

g) What level of confidence does Burlington Hydro have in the accuracy of the project cost estimates, and what steps have been taken to validate or benchmark these costs?

Response:

a) BHI projects that 15% of its meter population will have failed by the end of 2025 based on actual failure rates. BHI has tracked meter failure statistics since 2011 and that rate has gradually increased from 0.4% annually to 1.4% annually, with an overall average of 1% since 2011. The projected 15% meter population failure was calculated based on the observed average failure rate of 1% failure annually over the 15-year period since the original smart meter deployment. This assumption is conservative relative to the failure rate data observed in the most recent five years as shown in BHI's response to part c).

b) BHI rolled out its first generation of smart meters from 2008 – 2011.

c) BHI provides the failure rate for smart meters for the last five years in Table 1 below.

Table 1

Year	Failure Rate
2020	1.25%
2021	1.16%
2022	1.50%
2023	1.42%
2024	1.40%

d) The manufacturer has indicated a maximum 20-year life for the meter under ideal operating conditions.

e) BHI will use a combination of internal and external contracted resources to execute this program. The majority of the work will be performed by external contracted labour. BHI does not anticipate having to hire any internal resources to execute meter replacements for this program.

f) Benefits such as improved billing accuracy, reduced outages, or customer engagement will be reflected through BHI's Electricity Distributor Scorecard measures (e.g. billing accuracy, SAIDI, SAIFI, CSAT). However, there are many operational factors that affect performance on these measures, in addition to AMI, so it will not be possible to isolate the benefits of AMI from other operational factors.

g) BHI's project cost estimates are dependent on the volume of meters to be replaced and the replacement price per meter. BHI is confident in its unit cost estimates because it is currently ordering and installing these AMI 2.0 (A4) smart meters when existing meters fail (i.e. it has actual unit cost data to base its project cost estimates on). In terms of the estimated volume, BHI's smart meter replacement strategy is to replace meters as they reach seal expiry and become due for reverification. BHI has reliable data on the timing of existing meters coming due for reverification, so it has confidence in the volume of meters to be replaced over the forecast period as well. There are still risks associated with the project cost estimates, including price escalation due to inflation, exchange rate fluctuations, and tariffs; however BHI's estimate is based on the best available information at the time of this filing.

2-Staff-6

Reference:
Pole Replacement Program
Ref 1: Exhibit 2, DSP Appendix A: Pole Replacement Program
Ref 2: EB-2020-0007, Exhibit 2, DSP

Preamble:
The following is the wood pole health index algorithm used in the asset condition assessment for poles in the current application.

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	8	A,B,C,D,E	4,3,2,1,0	32
Pole Treatment	2	A,C,E	4,2,0	8
Remaining Strength	16	A,C,E	4,2,0	64
Wood Rot	5	A,E	4,0	20
Out of Plumb	3	A,C,E	4,2,0	12
Defects	2	A,B,C,D,E	4,3,2,1,0	8
Cracks	3	A,B,C,E	4,3,2,0	12
			Total score	156

Please see below for the wood pole health index algorithm used in the asset condition assessment for poles provided in Burlington Hydro's 2021 cost of service application.

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Remaining Strength	8	A,B,C,D,E	4,3,2,1,0	32
Wood Rot	6	A,B,C,D,E	4,3,2,1,0	24
Mechanical Defects	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Out of Plumb	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**92**

Question(s):

a) Please explain why Burlington Hydro replaced 33% less wood poles during the 2021-2025 than initially planned while the costs were 48% higher than the 2021 approved budget of $850k.

b) How frequently is the remaining strength tested for poles over 30 years old, and what percentage of those poles are tested on average annually?
c) Please explain how Burlington Hydro determines the acceptable threshold for the percentage of wood poles in very poor or poor condition? Please explain.
d) How does the cost of reinforcement using PoleEnforcer compare to full replacement over the asset lifecycle?
e) The ACA indicates that 93% of wooden poles are in fair or better condition. Please clarify how the ACA findings support the decision to increase the annual pole replacement rate from 87 to 104, along with the reinforcement of an additional 50 poles per year using PoleEnforcer.
f) In the wood pole health index algorithm from the 2021 cost of service application, the weighting for service age was the second lowest while in the current algorithm service age receives the second highest weighting. Please explain the reasoning for this change.
g) In the wood pole health index algorithm from the 2021 cost of service application, the weighting for wood rot accounted for 26% of the maximum score (=24/92) while in the current algorithm it only accounts for 13% (=20/156). Please explain the reasoning for this change.

Response:

a) BHI replaced less wood poles from 2021-2025 than initially planned at a higher overall cost than the 2021 approved budget due to the following reasons.

   - Higher than planned inflation over the 2021-2025 period. Adjusting for the impact of OEB inflation indicates that approximately half of the cost variances is attributable to inflation[1].

   - Material costs rose significantly due to COVID-19 and related supply chain issues. Wood pole prices increased by about 66% between 2020 and 2024.

   - There were more reactive pole replacements than initially planned due to increased failure rates and reliability concerns in this asset class. As detailed in BHI's response to 2-Intervenor-62 a), reactive replacements generally incur higher costs compared to planned replacements.

b) Remaining strength is tested for poles over 30 years old every 3 years[2]. On average, 33% of these poles would be tested annually based on a 3-year cycle.

[1] 2-Staff-20 d)
[2] DSP, Table 5.3-16

c) The acceptable threshold for the percentage of wood poles in poor/very poor condition is based on the overall risk associated with these assets (i.e. likelihood and impact of failure) which allows BHI to prioritize their replacements as part of its asset management strategy. Poles that are deemed critical in the budget year are identified for immediate replacement.

d) BHI has assumed the use of Pole Enforcer is about 10-20% of the cost of full replacement (depending on location and other factors) and can extend the useful life of a pole by up to 20 years (assuming no additional pole deficiencies). BHI is implementing a pilot program in 2025 to confirm the full cost and benefit of Pole Enforcer versus replacement.

e) The ACA findings support the decision to increase the annual pole replacement rate as they show that BHI has 1,006 poles in very poor condition. Per BHI's response to 2-Intervenor-62, BHI had 37 pole failures from 2021 to 2025 YTD and replaced 115 reactively. BHI is proposing an increase in pole replacements and reinforcement to reduce the number of pole failures and reactive replacements over the forecast period to minimize safety and reliability risks, and stabilize unit cost performance.

f) The change in weighting for service age was driven by evolving framework changes by BHI's ACA consultant (BBA), who conducted both of BHI's ACA studies. Even though the ranking of the service age weighting went from second last to second highest, it only changed from 13% (=12/92) to 20% (=32/156). Since 2021, BBA has continued to improve and refine its asset condition framework, to account for the latest industry trends and data, standardization of approaches, etc.

g) The change in the weighting for wood rot is mainly driven by the inclusion of two additional condition parameters in BHI's 2024 ACA due to improved data availability. BBA's continued refinement of its asset condition framework, as discussed in part f), also contributed to the change.

2-Staff-7

Reference:
System Access - Underground
Ref 1: Chapter 2 Appendices, 2-AA
Ref 2: EB-2020-0007 (Burlington 2021 CoS), Chapter 2 Appendices, 2-AA

Preamble:
In Burlington Hydro's 2021 cost of service application, the OEB approved $850k of net capital expenditures for General Service – Underground work. From 2021-2025, the net actual capital expenditures is an average of $1.56M annually, approximately a $710k or 84% increase from OEB approved.

Question(s):

a) Was the increase in underground work driven by a shift from directly buried cables to the installation of new cables in conduits? If not, please explain.

b) Are back-to-back feeds being implemented in new subdivisions?

Response:

a) The increase in underground work was not driven by a shift from directly buried cables to the installation of new cables in conduits; this was BHI's practice / standard in its 2021 Cost of Service application as well. This increase is driven by inflationary factors and operational factors. As identified in BHI's response to 2-Intervenor-14, inflation accounts for approximately 40% of the increase in average annual net capital expenditure costs between the historical and forecast period. Operational factors include increased complexity of projects; updated requirements from the City of Burlington to install underground plant in new developments and rising material and labour costs (over and above what is accounted for by OEB inflation).

b) Yes, BHI requires a loop system or back-to-back feeds for all new subdivisions.

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2-Staff-8

Reference:
Subdivisions
Ref 1: Exhibit 2, DSP Appendix A: Subdivision

Question(s):

a) Has Burlington Hydro conducted any preliminary assessments or scenario planning to evaluate how the CAM amendments might apply to current or future development areas within its service territory? If yes, please provide a summary of the areas assessed and the criteria used.
b) Do the capital contributions forecast in the application include the impact of the changes to the DSC to extend the connection horizon and the revenue horizon?
c) Does Burlington Hydro intend on using the Extended Horizons Variance Account?

Response:

a) No, BHI has not carried out any preliminary assessments or scenario planning to evaluate how the CAM amendments might apply to current or future development areas within its service territory. In anticipation of these amendments coming into force in September 2025, BHI has started preliminary discussions with its municipal partners in prioritizing growth intensification areas with identified capacity constraints, as potential candidates for a future CAM application.

b) Yes, the capital contributions forecast in the application include the impact of the changes to the DSC to extend the connection horizon and the revenue horizon.

c) No, BHI does not intend on using the Extended Horizons Variance Account, subject to any code amendments or other policy changes that would impact the capital contribution assumptions embedded in BHI's application.

2-Staff-9

Reference:
Gross Capital Costs
Ref 1: Chapter 2 Appendices, Tab 2-AA
Ref 2: Chapter 2 Appendices, Tab 2-AB

Question(s):

a) The subtotals for gross capital costs for each of System Access, System Renewal, System Service and General Plant do not match for all years. Please revise.

Response:

a) The Tab 2-AA subtotals for gross capital costs for each of System Access, System Renewal, System Service and General Plant do not match the Tab 2-AB subtotals for all years due to inclusion of the Miscellaneous line item in Tab 2-AA as per the format provided in the filing requirements. No revision is required.

   BHI has updated its capital expenditure forecast in response to 1-Staff-1 and provides updated Chapter 2 Appendices as Attachment_OEB_Chapter2Appendices_BHI_07242025.

2-Staff-10

Reference:
Underground cable testing and underground rebuild program
Ref 1: Exhibit 2, DSP Part 1 of 3, page 18
Ref 2: Exhibit 2, DSP Part 1 of 3, page 220 (Material Narrative, Underground Rebuilds)
Ref 3: Exhibit 2, DSP Part 2 of 3, Asset Condition Assessment

Question(s):

a) Please provide the SAIDI and SAIFI for underground cables for years 2021-2024.
b) Please provide the costs for underground cable testing for 2021-2024 and forecasted for 2025. Where are these costs captured and shown in the application?
c) Has the number of cable faults trended down in areas where proactive replacement or rejuvenation has already occurred?
d) Does underground cable testing consider areas with high customer impact and critical load served?
e) What is the estimated cost per km for cable replacement vs. rejuvenation, and how do these compare over the lifecycle of the asset?
f) Of the $2.1 million budget proposed for underground rebuild work in the 2026 test year, how much is allocated for cable replacement vs. cable rejuvenation?
g) What are the projected cost savings from cable rejuvenation, and how is success measured (e.g., reduction in repeat failures, extended life)?
h) Are underground rebuild projects coordinated with municipal roadwork or other planned utility upgrades to optimize costs and minimize disruption? If so, how is this coordination managed and factored into project planning and prioritization?
i) How will the effectiveness of the 2025 cable rejuvenation pilot program be tracked and reported?
j) Does Burlington Hydro anticipate that the increased capital investment in underground rebuilds will lead to a reduction in OM&A costs related to underground cable maintenance?
k) Please estimate the portion of the increase in the underground rebuild program costs is attributable to the deterioration of asset conditions, as opposed to rising unit costs for underground rebuild work.
l) Burlington Hydro stated that upgrading from direct buried to conduit installation is to meet current standards. Please confirm which standards this is referring to.

Response:

a) BHI provides the SAIDI and SAIFI for underground cables for the years 2021-2024 in Table 1 below.

Table 1

Underground Cable	2021	2022	2023	2024
SAIDI	0.17	0.22	0.22	0.08
SAIFI	0.04	0.08	0.10	0.07

b) BHI provides the costs for underground cable testing for 2021-2024 and forecasted for 2025 in Table 2 below. These costs are included in the “Pole/Cable Testing” line of Table 30 in Exhibit 4.

Table 2

	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast
Cable Testing	$ -	$ 56,925	$ -	$ 168,118	$ 160,000

c) Yes, the number of cable faults have trended down in areas where proactive replacement or rejuvenation has already occurred. While BHI does not track area-specific SAIDI or SAIFI, it can confirm that sections of cables that have been replaced as part of this program during the historical period have not seen repeat failures.

In 2025, cable rejuvenation was piloted as a cost-effective alternative to cable replacement on two cable segments in an identified subdivision with a history of cable faults. Early results have been encouraging, with no further cable faults reported in the rejuvenated sections of cables.

d) Yes, underground cable testing considers areas with high customer impact and critical load served. BHI’s cable testing strategy focuses on areas with a known history of cable faults and customer reliability impacts, which is based on data from distribution system records, field inspections and outage records.

e) The estimated average cost per km of cable replacement versus cable injection (rejuvenation) for the 2026 Test Year is shown in Table 3 below. BHI’s cable injection vendor has experienced average cable replacement deferrals of 25 years through rejuvenation, however there are a number of other factors to consider to do a complete cost comparison over the lifecycle of these assets, which BHI is still assessing through its pilot program.

Table 3

Method	Est. average per unit cost (m) $	Est. cost / km $
Cable replacement	262	262,000
Cable injection	79	79,000

f) The proposed budget for underground rebuild work in the 2026 test year is allocated $1.36M for cable replacement and $730K for cable rejuvenation. The exact allocation will depend on if BHI has to reactively replace any cable, which could reduce the amount of budget available for cable injection, and the number of cable sections identified as good candidates for cable injection, which is dependent on factors like the number of existing splices and the results from cable testing.

g) The projected cost savings from cable rejuvenation will depend on the length of cable rejuvenated vs. replaced. See BHI's response to part e) for an estimate of the unit cost savings. Success will be measured through:

- Number of repeat failures in the injected sections;
- Extended service life (beyond the estimated useful life of the injected sections); and
- Deferred costs.

h) BHI exchanges information with the City of Burlington, Halton Region, and other utilities with respect to each other's capital investment programs through the Burlington Joint Utility Committee (BJUC) to discuss timelines and schedules to coordinate planning, design and construction activities. Where these programs overlap in terms of location and scope BHI coordinates with these stakeholders to re-prioritize planned investments to coincide with other projects to achieve cost savings for the rate payers. In addition, BHI complies with Municipal Consent Applications to ensure the City of Burlington, Halton Region, and other utilities are aware of ongoing BHI projects that could affect them.

i) Please see BHI's response to part g).

j) No, BHI does not anticipate that the increased capital investment in underground rebuilds will lead to a reduction in OM&A costs related to underground cable maintenance, as these costs are related to cable testing. BHI must continue its cable testing program in order to identify candidates for cable rejuvenation and/or replacement. Increased renewal could lead to a reduction in Operating costs (e.g. outage response), but these savings will be realized over a longer period of time. BHI has 227km of underground cable in poor or very poor condition and is only targeting to replace or rejuvenate ~14.5km per year.

k) All of the increase in the underground rebuild program costs is attributable to the deterioration of asset conditions. In BHI's last ACA, approximately 20% of its underground cable was in poor or very poor condition. That has increased to 33% in BHI's most recent ACA. The average number of cable faults has increased 15%, from 24 per year over the 2015-2019 period[1] to 28 over the 2020-2024 period[2]. Per BHI's response to 2-Intervenor-61 a), forecasted underground cable replacement cost per unit is expected to stabilize over the forecast period, not increase.

l) Upgrading from direct buried to conduit installation is in accordance with BHI's standards.

[1] 2-Intervenor-61 c)
[2] DSP, Table 5.4-11

2-Staff-11

Reference:
Transformer Replacements
Ref 1: Exhibit 2, DSP Part 1, p. 137
Ref 2: Exhibit 2, DSP Part 1, p. 37
Ref 3: Exhibit 2, DSP Part 1, p. 118
Ref 4: EB-2020-0007, Response to 2-Staff-15c

Preamble:
Burlington Hydro provided the following table on reactive vs. proactive asset replacements from 2021 to 2024.

Table 5.2-6: Reactive vs Proactive Asset Replacements

Program	Reactive/ Proactive	2021		2022		2023		2024	
		Qty	$000	Qty	$000	Qty	$000	Qty	$000
MS Feeders Cable Replacement (meters)	Proactive	1,784	129	0	12	1,381	135	0	0
	Reactive	520	95	3,113	293	0	0	0	4
Pole Replacement Program (units)	Proactive	69	915	51	711	77	1,032	75	1,130
	Reactive	15	203	26	421	32	340	18	302
Replacement Substation Circuit Breakers (units)	Proactive	3	118	3	158	2	113	2	93
Station Transformer Replacement Program (units)	Proactive	1	319	1	1,011	0	205	1	476
	Reactive	0	0	0	0	0	0	0	32
Switch Replacement Program (units)	Proactive	17	205	3	38	29	146	9	141
	Reactive	15	144	16	338	27	471	17	272
Switchgear Replacement Program (units)	Proactive	2	293	1	100	0	2	2	159
	Reactive	0	0	0	0	0	0	0	0
Transformer Replacement (units)	Proactive	14	201	1	63	14	193	16	255
	Reactive	32	421	37	285	32	420	75	734
Underground Rebuilds (meters)	Proactive	1,038	181	90	106	0	18	1,788	246
	Reactive	1,549	634	3,856	894	7,675	1,957	1,199	1,035

Question(s):

a) For 2024, Burlington Hydro exceeded the System Renewal budget by $2.4M, representing a 75% increase. Part of its explanation for the variance was increased expenditures to replace faulty and leaking transformers. The table above shows that in 2024 the total number of transformer replacements was 91, over twice the number which were replaced in the historical period. Was the increase in transformer replacements directly attributed to faulty and leaking transformers? If not, please explain.
b) Burlington Hydro sates that very few of its transformers are currently in poor or very poor condition, based on its most recent Asset Condition Assessment, consistent with its 2020 ACA. However, the utility notes that transformers can deteriorate quickly from fair to poor condition. How frequently are inspections performed on transformers rated as "Fair"?
c) Does Burlington Hydro notice a decrease in costs as a result of efforts to increase proactive replacements and reduce the number of reactive replacements?

Response:

a) Yes, the increase in transformer replacements in 2024 is attributed to an increase in faulty and leaking transformer replacements.

b) Inspections are performed on distribution assets on a 3-year cycle, as per Appendix C of the DSC, regardless of asset condition category.

c) BHI has noticed a decrease in costs as a result of its efforts to increase proactive replacement and reduce the number of reactive replacements. Programs like pole replacement[1] and switch replacement[2] exhibit significantly lower unit costs when assets are replaced proactively vs. reactively. However, the volume of reactive replacements over the historical period has impeded BHI’s efforts to increase proactive replacements, which is one of the main drivers of increasing System Renewal costs since 2021. Underground rebuilds are an example where BHI reactively replaced significantly more assets than it did proactively. Part of the reason for BHI’s proposed increases in System Renewal spending is to proactively address more deteriorated assets before they fail or need to be replaced reactively.

[1] 2-Intervenor-62 a)
[2] 2-Intervenor-68

2-Staff-12

Reference:
ACM – SCADA/ADMS Upgrade
Ref 1: Exhibit 2, Appendix B, Business Case
Ref. 2: Exhibit 2, DSP Part 1 of 3, p. 150

Question(s):

a) Please provide a high-level cost breakdown of the SCADA/ADMS project costs of the preferred option that does not divulge commercially sensitive unit costs.
b) Burlington Hydro's business case estimates the investment for SCADA replacement and ADMS acquisition at approximately $3.5 million. However, the overall project budget is listed as $3.64 million. Please clarify the reason for the $110k difference.
c) Has a net present value or cost-benefit analysis been conducted on the preferred investment and the alternatives that were considered? If yes, please provide the analysis. If not, please explain why.
d) Burlington Hydro states that the proposed integrated SCADA and ADMS solution is being sourced from the same vendor as Burlington Hydro's existing OMS provider. Please clarify whether a competitive procurement process was conducted for this project. If not, please explain how this aligns with the Burlington Hydro's procurement policy.
e) The vendor estimation includes costs associated with ADMS maintenance for years 1-9.
   i. Please describe these costs.
   ii. Are these costs part of the total cost of $3.64M?
   iii. Will these costs be capitalized or included as part of the proposed OM&A budget?
f) The business case states that the vendor costs do not include costs associated with integrating with Burlington Hydro's existing applications or the cost of field hardware and that Burlington Hydro will be in a better position to accurately forecast these costs as part of the project preparation phase.
   i. Does Burlington Hydro have a preliminary budget for integrating existing field hardware with existing applications, and procuring the necessary new field hardware?
   ii. Would it be more prudent to install the ADMS after the necessary field hardware has been installed? Please explain.
   iii. What percentage of field hardware is already in place?
   iv. What are the potential risks if the costs associated with integration and new field hardware are significantly higher than anticipated, and how does Burlington Hydro plan to manage these uncertainties given that these costs are not yet included in the current estimate?

g) At a high-level, when does Burlington Hydro expect each phase of the project noted in the project implementation section to be completed?
h) The implementation plan only mentions the ADMS portion of the implementation. Please provide a rough timeline of when the SCADA system will be replaced.
i) Are any internal staff assigned to this project? If so, have they already been hired and onboarded?

Response:

a) BHI is unable to provide a high-level project cost breakdown that does not divulge commercially sensitive unit costs. Disclosing this information at a more detailed level could prejudice the competitive position of the vendor in any future negotiations related to the provision of similar services.

b) The price of the SCADA/ADMS project business case ($3.5M) was in 2025 dollars. The estimated cost in BHI's DSP ($3.64M) has been adjusted for inflation to reflect the expected costs in 2027 dollars.

c) Yes, BHI conducted a qualitative cost-benefit analysis on the preferred investment and the alternatives that were considered for the SCADA Replacement /ADMS Implementation across several criteria. The alternatives considered were 1. Status Quo, 2. SCADA Replacement only, and 3. SCADA Replacement/ADMS Implementation. The analysis is summarized in Figure 1 and Table 1 below. The rankings from 1-5 represent the ability of the solution to meet each criteria with 1 = least able and 5 = most able. BHI performed a cost analysis when it replaced its OMS in 2024. Further details on this process are provided in BHI's response to 2-Intervenor-27 and in the OMS business case filed as Appendix 2-Intervenor-26h).

Figure 1

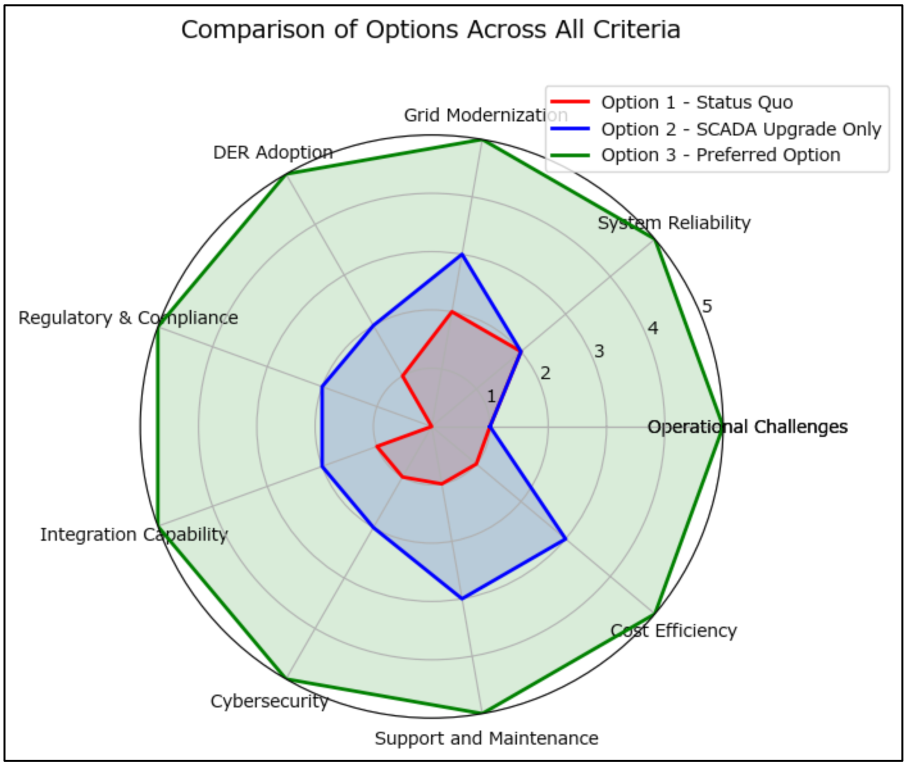

Comparison of Options Across All Criteria
Option 1 - Status Quo
Option 2 - SCADA Upgrade Only
Option 3 - Preferred Option
Grid Modernization
System Reliability
Operational Challenges
Cost Efficiency
Support and Maintenance
Cybersecurity
Integration Capability
Regulatory & Compliance
DER Adoption
1
2
3
4
5

Table 1

Criteria	Description	Option 1 - Status Quo (Do Nothing)	Scoring Matrix (1-5) Option 1	Option 2 - SCADA Replacement Only	Scoring Matrix (1-5) Option 2	Option 3 - Preferred Option (Replace SCADA / Implement ADMS)	Scoring Matrix (1-5) Option 3
Operational Challenges	Assess the current operational challenges and how they are addressed	Significant increase in risk of operational challenges	1	Lack of full benefits of grid automation and optimization	1	Provide full known benefits of grid automation and optimization	5
System Reliability	Ability to operate without failures or downtime	increasing likelihood of long outages and slower response	2	Would not enable advanced automation in system control	2	Options to enable advanced automation in system control	5
Grid Modernization	Improve grid efficiency with increasing energy demands	existing system cannot effectively manage bidirectional power flows	2	partial grid modernization without dynamic load balancing	3	Full grid moderanization without dynamic load balancing	5
DER Adoption	Increasing integration of decentralized energy	existing system cannot manage DERs, leading to reliability challenges	1	Will be difficult to manage DERs properly without full ADMS	2	Capable of managing DERs with full ADMS solution	5
Regulatory & Compliance	Risk to operations, finances or changes in regulations	non compliance with OEB requirements for reporting	0	will not meet OEB's evolving expectations	2	Will be better positioned to meet OEB evolving expectations	5
Integration Capability	Ease of integrating with other systems	Integration is limited and not bidirectional	1	Full end to end seamless integration will not be available.	2	Full end to end seamless integration will be available	5
Cybersecurity	Robustness of security measures against threats	security vulnerabilities exploitation risk due to lack of controls	1	manual controls compared to automated controls	2	Automated controls build into the converged system	5
Support and Maintenance	Quality of technical support and system updates	aging SCADA infrastructure is becoming difficult to maintain	1	without ADMS, support and maintenance options will be limited	3	Full solution maintenence and support options by manufacturer	5
Cost Efficiency	Value for money compared to features and benefits	SCADA system is becoming expensive to maintain due to legacy integrations	1	TCO will be higher without ADMS	3	Cost will be manageable given the fully integrated solution	5

1 = least feasible to meet each criteria, and 5 = most feasible to meet each criteria

d) BHI followed a competitive procurement process in selecting a vendor for its OMS project which is a key building block for a utility to transition to an ADMS operating paradigm. BHI's strategy when it selected its OMS vendor was to partner with one vendor who could meet BHI's OMS needs and support its transition to an ADMS over time. This approach is expected to minimize integration and transition issues and reduce overall project risk. Please refer to BHI's responses to 2-Intervenor-27 a) and b) for more information.

e)

i. ADMS maintenance costs are related to product lifecycle management, for example, product upgrades, patches installation, product support and features support.
ii. These costs are not part of the total cost of $3.64M. These maintenance costs will be recorded in OM&A.
iii. These costs will be included as part of the proposed OM&A budget in Software Licensing, Maintenance and Support under the IT program.

f)

i. BHI does not have a preliminary budget for integrating existing field hardware with existing applications, and procuring the necessary new field hardware.

ii. It would not be more prudent to install the ADMS after the necessary field hardware has been replaced. This would delay the ADMS implementation, without which BHI's grid operations would be exposed to unnecessary risks, including inadequate security and limitations on DERMS integration. The ability to deliver the outcomes, as outlined 149-150 of the DSP would be unnecessarily delayed.

   BHI plans to pace the replacement of its field hardware over multiple years to mitigate rate impact and allow for non-BHI communications infrastructure required for connectivity to be installed. BHI will prioritize ADMS integration with existing SCADA-enabled devices to modernize grid management capabilities in response to increased demand, electrification and DER penetration.

iii. BHI estimates that 20-30% of field devices are connected to BHI's existing SCADA system and as such are expected to be capable of seamlessly integrating with the new SCADA / ADMS system without incurring additional costs.

iv. BHI plans to estimate the integration and field hardware costs during the discovery and planning phase of the project in 2026. BHI will assess the impact of those costs on the overall capital budget and implementation timeline at that time. As mentioned above, BHI plans to adopt a phased approach for integration and remaining field hardware replacement, and expects that existing SCADA field connected devices will be able to be connected to ADMS without incurring additional costs. The remaining field devices, that are currently not connected to the existing SCADA system, are planned to be replaced in phases over the next several years, which will enable BHI to pace and control the cost.

g) BHI is unable to provide the requested information at this time because it intends to commence the SCADA replacement and ADMS acquisition project in 2026 at which time it will review needs, requirements and implementation timelines associated with the project. This review will entail a current system assessment for replacement readiness, developing the design architecture, and consideration of timelines associated with development, testing, staged deployment, and training.

h) Refer to 2-Staff-12 (g).

i) As discussed in 4-Staff-65(a) BHI intends to hire a Supervisor of System Planning and Grid Modernization whose responsibilities will include planning, implementing, and SCADA and ADMS project and operating the new system. Resource planning, including the assignment of personnel, and determination of necessary tools, will be addressed in 2026 during the detailed planning stages discussed in 2-Staff-12(g).

2-Staff-13

Ref 1: Exhibit 2, Appendix A DSP, Part 1 of 3, p.15

Ref 2: Exhibit 2, Appendix A DSP, Part 1 of 3, pp. 141-143

Ref 3: Exhibit 2, Appendix A DSP, Part 1 of 3, p. 33

Preamble:

Burlington Hydro, in its Distribution System Plan, indicates that expenditures related to system service are partially driven by operational objectives aimed at integrating Distributed Energy Resources (DERs). The plan further states that system service investments involve modifications to Burlington Hydro's distribution system to, among other purposes, enhance DER integration. Under the section titled "Renewable Energy Generation (REG)," Burlington Hydro notes that it does not anticipate any significant investments to facilitate new DER connections during the 2026–2030 period.

Question(s):

a) Given that not all DERs involve energy generation, please identify and describe the types of DERs that Burlington Hydro anticipates this increased expenditure will support the integration of.
b) Please provide an estimate of the number of DERs that Burlington Hydro expects this increased expenditure will support the integration of over the applicable rate period.
c) Please describe the value that this expenditure is expected to deliver to ratepayers, including any anticipated operational, reliability, or economic benefits.

Response:

a) BHI's investments in System Service which include installation of smart field devices (intelligent switches) and conversion to the AMI 2.0 network (collector and communication system for data integration with ADMS), will be key to enabling DERs across BHI's distribution network. These expenditures will facilitate DER integration through real-time visibility, monitoring and control, as well as enhanced system availability that allows for minimal disruption during faults through dynamic reconfiguration of load. They will also support DER dispatch as part of any future DSO model.

The types of DERs that BHI anticipates this increased expenditure will support the integration of include:

1. Managing Electric Vehicles (EVs) Loads

High charging loads, especially during peak hours, can stress local transformers and distribution lines. Access to real-time charging data will help BHI manage these loads and plan for potential infrastructure upgrades.

2. Battery Energy Storage Systems (BESS)

While BESS can help balance supply and demand, large-scale or aggregated storage systems require advanced control and communication systems. These can be integrated by leveraging the existing communication networks. Enhanced system availability will help dispatch this capacity as needed.

3. Controllable Loads (e.g., smart appliances, HVAC systems)

New technologies in demand response (DR) facilitate electrification and the energy transition for existing customers but require real-time communication and control infrastructure. Investment in advanced metering infrastructure (AMI) will allow integration and management of communication networks, and these DR platforms.

b) BHI does not have an estimate of the total number of DERs that this increased expenditure will support the integration of over the applicable rate period. BHI expects that DER integration efforts will extend beyond the 2026-2030 rate period, as “Ontario is launching a focused plan to better integrate these assets into the electricity system”[1] to pursue the potential of these resources to “relieve constraints, defer costly infrastructure, and improve overall efficiency.”[2] Foundational investments in technologies such as Advanced Distribution Management System (ADMS) and smart field devices are required to implement these policy objectives, and deliver other benefits to customers as noted in part (c).

[1] Energy for Generation: Ontario Integrated Plan to Power the Strongest Economy in the G7 pp.87,89
[2] Energy for Generation: Ontario Integrated Plan to Power the Strongest Economy in the G7 p.87.

c) The value of the noted investments is outlined in the evidence filed in Sections 5.2.1.2.3, 5.2.1.3, 5.2.1.4, 5.4.1.2.3, 5.4.2, and Appendix A MISD (SCADA Replacement / ADMS Acquisition) of the DSP, and includes:

- **Operational Benefits**: Transition to the next generation AMI 2.0 system with real-time integration with BHI's OMS and Customer Information System ("CIS"). Upgrading BHI's SCADA system including implementation of an ADMS to modernize grid management capabilities in response to increased demand, electrification, and DER penetration.
- **Reliability (and resilience) Benefits:** BHI's investments in AMI and smart grid technologies such as SCADA, reclosers, switches, and sensors support improved reliability and reduced interruption impacts across the grid during adverse weather events.

2-Staff-14

Reference:
Consideration of Non-Wire Solutions (NWS) to address system needs
Ref 1: Exhibit 2, Appendix A DSP, Part 1 of 3, p. 107
Ref 2:

Preamble:
Burlington Hydro states that it conducted an Energy Storage Feasibility Study in 2024 to evaluate the potential for integrating Battery Energy Storage Systems (BESS) into its distribution grid. In section 5.3.5, "Non-Wires Solutions (NWS) to Address System Needs," Burlington Hydro concludes that BESS does not present a suitable NWS option for any of the Midtown Transit Station Area (MTSA) projects.

Question(s):

a) Please provide an overview of the 2024 Energy Storage Feasibility Study, including the scope of the study, key findings, and conclusions.

Response:

a) BHI has filed the Energy Storage Feasibility Study in response to 2-Intervenor-40. Please refer to the Executive Summary of the study for an overview of the scope, key findings, and conclusions.

2-Staff-15

Reference:
Dundas Street Widening – Walkers Line by Appleby Line
Ref 1: EB-2020-0007, VECC-4 f)
Ref 2: EB-2020-0007, Draft Rate Order Reply Submission

Preamble:
At reference 1, Burlington Hydro stated that the Dundas St Road Widening (Walkers Line to Appleby Line) project was not completed in 2021 or subsequent years because the project was delayed by the road authority.

At reference 2, Burlington Hydro clarified that while the full scope of the 2021 Dundas Street Road Widening Project was not completed as originally budgeted, a portion of the project was completed, resulting in the construction and energization of capital assets—including 20 poles and 2 transformers—at a cost of $517,315. Burlington Hydro stated that these assets are currently in use, which makes the asset “used and useful”.

Burlington Hydro stated that the capital expenditures were necessary to relocate infrastructure in compliance with the Public Service Works on Highways Act, due to road widening by the local authority. The installed line, fed by two 27.6 kV circuits from Palermo TS, is critical to supplying electricity to northeast Burlington.

Question(s):
a) Please provide a detailed breakdown of the original project scope versus what was actually completed and put into service at a cost of $517,315.
b) Please provide the kms and a map of the Dundas Road Widening project that identifies the sections completed to date, planned for completion in 2025 and those planned for completion during the 2026-2030 period.
c) What specific components of the project were deferred or cancelled?
d) Please confirm which project the $517,315 portion of the Dundas Street Road Widening project is captured in Tab 2AA of the Chapter 2 Appendices spreadsheet in the current application.

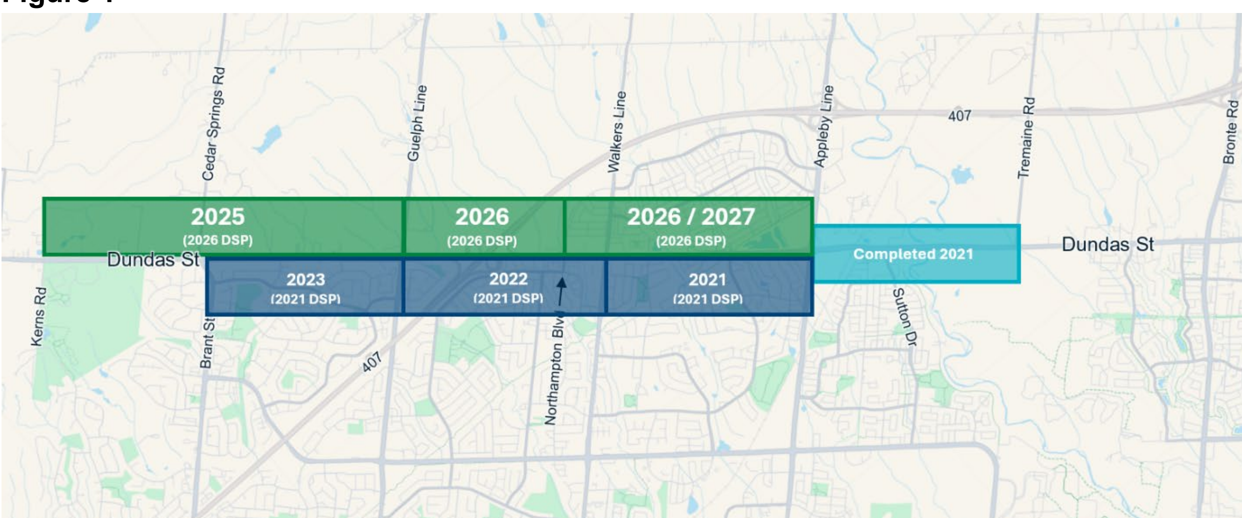
Response:
a) The original scope of the 2021 Dundas St. Road Widening (Walkers Line to Appleby Line) included relocation of BHI’s assets along Dundas St. from Tremaine Road to Appleby Line to Walkers Line. The total estimated cost of the project was $3,035,948 net of capital contributions. Only the portion of the project from Tremaine Road to Appleby Line was completed in 2021 at a cost of $517,315 net of capital contributions. BHI provides in Table 1 below a detailed breakdown of the original project scope versus actual work completed.

Table 1

	2021 Budget			2021 Actual		
Appleby to Tremaine	**Overhead**	**Underground**	**Total**	**Overhead**	**Underground**	**Total**
Gross Capital Expenditures	$869,530	$0	$869,530	$763,416	$522,309	$1,285,725
Capital Contributions	($359,745)	$0	($359,745)	($277,280)	($491,130)	($768,410)
Net Capital Expenditures	$509,785	$0	$509,785	$486,136	$31,179	$517,315
Walkers to Appleby	**Overhead**	**Underground**	**Total**	**Overhead**	**Underground**	**Total**
Gross Capital Expenditures	$1,684,122	$2,105,153	$3,789,275	$0	$0	$0
Capital Contributions	($561,374)	($701,739)	($1,263,113)	$0	$0	$0
Net Capital Expenditures	$1,122,748	$1,403,414	$2,526,162	$0	$0	$0
2021 Dundas St. Rd Widening (Total)	**Overhead**	**Underground**	**Total**	**Overhead**	**Underground**	**Total**
Gross Capital Expenditures	$2,553,652	$2,105,153	$4,658,805	$763,416	$522,309	$1,285,725
Capital Contributions	($921,119)	($701,739)	($1,622,858)	($277,280)	($491,130)	($768,410)
Net Capital Expenditures	**$1,632,533**	**$1,403,414**	**$3,035,948**	**$486,136**	**$31,179**	**$517,315**

b) BHI provides a map of the Dundas Road Widening project sections in Figure 1 below. The blue sections reflect the planned implementation dates from BHI's 2021 DSP and the green sections reflect the planned implementation dates from BHI's 2026 DSP.

Figure 1



<u>Sections completed to date:</u>

- Appleby Line to Tremaine Road
    - See "Completed 2021" section of Figure 1;
    - Approximately 2 km.

Planned for completion in 2025:

- Guelph Line to Kerns Road
  - See green section "2025 (2026 DSP)" in Figure 1;
  - Approximately 3.65 km.

Planned for completion during the 2026-2030 period

- Northampton Boulevard to Guelph Line
  - See green section "2026 (2026 DSP)" in Figure 1;
  - Approximately 1.65 km.

- Appleby Line to Northampton Boulevard
  - See green section "2026/27 (2026 DSP)" in Figure 1;
  - Approximately 2.5 km.

c) The original scope of work as included in BHI's last application[1] and the status of each of the phases are as follows (refer to Figure 1 for a visual depiction):
- Appleby Line to Tremaine Road (2021)
  - Completed in 2021.
- Walkers Line to Appleby Line (2021)
  - Deferred. Now part of the Appleby Line to Northampton Boulevard phase planned for 2026/27.
- Guelph Line to Walkers Line[2] (2022)
  - Deferred. A portion of this original scope is now included in the Appleby Line to Northampton Boulevard phase planned for 2026/27 and the other portion is included in the Northampton Boulevard to Guelph Line phase planned for 2026.
- Guelph Line to Brant Street[3] (2023)
  - Deferred. Now part of the Guelph Line to Kerns Road phase planned for 2025.

[1] EB-2020-0007
[2] EB-2020-0007, 2-SEC-12
[3] Ibid

d) The $517,315 portion of the Dundas Street Road Widening project is captured in the "Dundas St Road Widening - (Appleby line to Tremaine)" line of Tab 2AA of the Chapter 2 Appendices spreadsheet in the current application. BHI incurred gross capital expenditures of $1,285,725 (per Tab 2AA) and received capital contributions of $768,410 for total net capital expenditure of $517,315.

2-Staff-16

Storm Hardening
Ref 1: Exhibit 2, DSP Part 1 of 3, p. 48
Ref 2: Exhibit 2, DSP Part 1 of 3, p. 17

Question(s):

a) Burlington Hydro states that it carried out key system hardening initiatives, including reinforcing poles and wires, vegetation management, replacing aging assets, and deploying smart grid technologies like SCADA reclosers, switches, and sensors to enhance system reliability during severe weather events. Please list all projects that were carried out as part of Burlington Hydro's grid hardening strategy.
    a. Of these projects, please confirm what percentage corresponds to typical annual System Renewal expenditure and what percentage was specifically allocated for grid hardening.

b) For each project type, please provide the criteria which Burlington Hydro uses to complete a cost-benefit analysis for system hardening projects.

Response:

a) In addition to the initiatives listed on page 17 of BHI's DSP, BHI is carrying out the following work as part of its grid hardening strategy.

Increased maintenance / asset replacements in vulnerable locations

- Prioritizing, and where necessary increasing, vegetation management activities on overhead infrastructure located in heavily treed areas that are impacted by high winds and storm events.
- Submersible transformer conversion program to mitigate the risk of outages from flooding in identified flood zone areas.

Standardized Hardening in Design Specifications

Engineering design standards include:

- Adoption of CSA C22.3 No. 1:20 that provides requirements for the construction of overhead systems, design, and clearances for electric supply and communication lines and equipment. The amendment published in 2022 focuses on improving resiliency of overhead systems to extreme climate events, while increasing system reliability, continuity of service, and safety.
- Where applicable, replacing aging infrastructure with assets built to current standards that include storm-hardened designs during scheduled renewals. (e.g., longer cross-arms for clearances, shorter spans in pole lines, higher class poles, etc.).

Leveraging GIS and Data Analytics

BHI is working with the City of Burlington to leverage GIS maps for overlaying asset locations within flood zones. This data can be used to inform the annual capital planning process for prioritizing asset replacements.

Coordination with Smart Grid Investments

Align system automation upgrades with grid-hardening objectives (e.g., expansion of BHI's "Intelli-team" by adding more intelligent switches which provides remote fault isolation and restoration for customers impacted by severe weather events).

a. BHI is unable to provide the requested breakdown because it does not allocate specific dollar amounts for grid hardening versus other asset management objectives that inform capital and maintenance investments. As indicated above, grid hardening is incorporated into BHI's system renewal, maintenance and system service investments, as part of an integrated approach to asset management.

b) Since BHI plans and executes capital and maintenance work in an integrated manner (i.e. addressing multiple objectives), it does not carry out a unique cost benefit analysis for projects that advance grid hardening objectives.

BHI applies the following criteria/factors to consider whether grid hardening should be incorporated into the scope of the project:

- The area the distribution system is servicing;
- The path the circuits take (through a treed area, or a major crossing);
- Legacy or new construction (the need to update to current more climate resilient standards); and
- The presence of alternate feeders (for back up and switching purposes).

2-Staff-17

Reference:
Enterprise Resource Planning
Ref 1: Exhibit 2, page 43
Ref 2: Exhibit 2, DSP part 1 of 3, p. 115
Ref 3: Exhibit 2, DSP part 1 of 3, p. 152
Ref 4: EB-2020-0007, DSP, p. 16

Question(s):

a) In Burlington Hydro's last cost of service application for 2021 rates, it indicated that a new ERP system was required during the forecast period and was planning to request approval for an Advanced Capital Module. Burlington Hydro states that it instead elected to upgrade its existing ERP in order to address immediate business needs. What were the specific reasons for the ERP replacement project being deferred in 2022 and 2023? In those years, why was it prudent to upgrade the existing ERP rather than carryout a complete replacement?
b) Has the scope of work changed since the project was initially proposed in the 2021 cost of service application?
c) Please provide a proposed timeline for implementation, including estimated milestones for the Request for Proposal process.
d) Please confirm when the $2.1M project cost estimate was developed and the process used to complete the estimate.
e) Will any internal labour be required for this project? If so, have these employees already been hired and onboarded?
f) Burlington Hydro states that the project is still in the early planning stages, and as a result a business case has not yet been developed to meet all the criteria for an Advanced Capital Module funding request. As such, Burlington Hydro is not seeking ACM approval for this project in this application but may consider applying for an ICM during the 2026–2030 period if it meets the ICM eligibility criteria. In which year does Burlington Hydro plan to apply for an ICM for the ERP replacement project?
g) Has Burlington Hydro considered deferring this project to the test year of the next cost of service application rather than planning to apply for an ICM during the IRM years?

Response:

a) The ERP replacement project was postponed to mitigate the impact of higher than planned System Renewal costs in 2022 and 2023, as noted in Table 5.4-4 and Table 5.4-5 of the DSP. In addition, the planning phase of the ERP project (requirement gathering, scope development, RFP process, etc.) would have started in 2021, but BHI had competing resource needs with other IT projects that required the same personnel for planning and implementation. These include:

- Customer Information System replacement in 2021, which was originally planned to be completed by the end of 2020;
- Customer Choice implementation in 2021 (unplanned);
- Higher than planned resources to integrate BHI's Geographic Information System with its Outage Management System in 2021 due to unexpected coding changes to proprietary OMS software;
- Green Button implementation in 2023 (unplanned); and
- Ultra-Low Overnight rate implementation in 2023 (unplanned).

Because it wasn't feasible to complete the ERP replacement, BHI had to upgrade the existing ERP to address immediate business needs and migrate to a version of the software that is covered by extended vendor support.

b) Yes, the scope of work has changed since the project was initially proposed in the 2021 Cost of Service application. BHI needs to consider an ERP solution in the context of modernizing processes, data operability and integration with new systems implemented, or to be implemented, since 2021 (OMS, CIS, GIS, AMI 2.0, ADMS, SCADA), the changing risk and cyber security threat landscape, compliance with OCSF, benefits of a cloud versus on-premise solution, ability to handle complex and financial and operational tracking for DERs, EV infrastructure, DSOs and storage projects, advanced data analytics, and vendor product support and resiliency.

c) BHI provides a high-level timeline for the project below. This timeline is subject to change because the project is still in the early planning stages.

Q3 2025:	Requirements and Needs Analysis including scope
Q4 2025:	Stakeholder Interviews
Q1 2026:	Identify vendors and products
Q2 2026:	RFP Process including Issuance and Proposal Assessment
Q2 2026:	Vendor Demos
Q3 2026:	Select Proponent and Award Contract
Q3 2026:	Project Implementation Start Date
Q2 2028:	Go Live

d) The process/steps BHI undertook to prepare the ERP cost estimate, are as follows:

- BHI leveraged its own experience from adopting and implementing other technologies and enterprise systems of similar complexity and scope such as CIS, GIS and OMS. Historical costs and lessons learned from these internal projects informed the estimate.
- Conducted an external market scan for publicly available information[1] and regulatory filings from other utilities, to validate and refine the project estimate.
- BHI sought informal and high-level feedback from peers in the industry of similar size or that had recently implemented a new ERP system. Their experience with project scope, challenges, and actual costs provided valuable ballpark benchmark data.
- Obtained and reviewed industry research from recognized market analysts, such as Gartner. This research aided in understanding the pros and cons of ERP implementations and technological trends. While cost estimates were not provided the technology intelligence helped to create a cost estimate.

The insights and data gathered from the above steps were synthesized to develop a single, high-level cost estimate. This estimate encompasses implementation, process migration and integration, and initial setup costs.

To the best of BHI's knowledge it is a reasonable estimate, but it is subject to variability/change based on factors outside of the control of management.

e) Yes, internal labour will be required for this project. Existing employees across several departments will be used to meet some of the requirements of the project such as requirements and needs analysis, stakeholder interviews, identifying vendors and products and the RFP process. In addition, employees who have not yet been hired or onboarded will be required to support the project during the implementation phase. These include some of the headcount proposed to be hired in 2026 including the financial analyst as identified on page 207 of Exhibit 4, the regulatory analyst (page 224 of Exhibit 4), the Senior Manager, Capital Planning & Supply Chain (page 225 of Exhibit 4), and engineering roles.

f) Based on the timeline provided in response to part (c), BHI anticipates applying for an ICM for the ERP Replacement Project in 2027.

[1] ERP Pricing in 2025: How Much Does a New ERP System Cost? – Software BattleCard

g) Yes, BHI considered deferring this project to the test year of the next cost of service application rather than planning to apply for an ICM during the IRM years and concluded that it is not practical or feasible to do so from a resourcing and functionality perspective.

   a. **Functionality:** Postponing ERP implementation would hinder BHI's ability to realize operational efficiencies through improved business processes and make it difficult to address increasing business demands and functional requirements. Notably, the current ERP system lacks or has limited capacity for several key functionalities, including financial forecasting and budgeting, comprehensive financial and operational tracking for DERS (such as supporting Capacity Allocation Model requirements, expansion deposits, and capital contributions), seamless integration with ancillary systems, and advanced work order analytics.

      Further, maintaining the existing ERP solution will increase costs and complexity due to (i) interface integration and (ii) the vendor moving away from customization options, to protect its product main development stream. The current ERP system also lacks modern cyber security controls to protect against evolving threat landscapes

      Practicality: Postponing the ERP replacement project until the next rebasing would result in BHI implementing the new ERP system at the same time as preparing the next Cost of Service application. This overlap would require key functions such as Finance, Engineering, and IT to participate in both projects, increasing resource demands in these portfolios and managing increased complexity in preparing and handling the data needed for the rate application while simultaneously transitioning BHI's financial data to the new ERP system.

2-Staff-18

Reference:
Other Computer Hardware & Software
Ref 1: Exhibit 2, DSP 1 of 3, p. 264

Preamble:
In its 2021 cost of service application, Burlington Hydro was approved for $188k for its test year budget for Other Computer Hardware and Software expenditures. From 2021 to 2025, Burlington Hydro spent on average $381k annually, $193k or 103% higher than the approved amount.

Historical and Bridge Years							Test Year
Projects	2021	2022	2023	2024	2025 Bridge Year	Average	2026
Other Computer Hardware & Software	98,105	380,257	617,764	356,473	457,200	381,960	484,500

For 2023 and 2025, Burlington Hydro had increased General Plant expenditures resulting from computer server replacements due to end-of-life equipment and lease expiry.

Question(s):

a) Please explain the higher spending for Other Computer Hardware & Software in 2023 and 2024.

b) The proposed budget for the forecast period varies significantly–the proposed 2026 test year budget is $485k while the average annual forecast budget is $361k, which is approximately 25.6% lower than the 2026 test year. Burlington Hydro states that investments in this program fluctuate annually based on evolving business needs and priorities identified throughout the year. Please explain why Burlington Hydro considers this level of year-over-year variability appropriate, especially the higher spending for the 2026 test year.

Response:

a) The reasons for the higher spending for Other Computer Hardware & Software in 2023 are as follows:

- ERP hardware expenditures (~$100k) related to BHI's ERP upgrade; these investments were required to ensure the ERP functioned effectively to manage and integrate various business processes;

- Server hardware renewal (~$123k) as part of 5-year replacement program to maintain the performance, security, and efficiency of IT infrastructure;
- Green Button implementation (~$96k), and
- System changes to implement Optional Enhanced TOU rates (~$109k).

The reasons for the higher spending for Other Computer Hardware & Software in 2023 are as follows:

- Networking hardware renewal (~$137k) as part of 5-year replacement program to maintain a reliable, secure, and high-performing network; and
- Continued Green Button implementation (~$78k).

b) Year-over-year variability in costs is appropriate because costs associated with implementation of IT/OT solutions vary due to business, legislative and regulatory requirements, complexity, integration, vendor related factors, revision of licensing costs by software providers, cyber security, infrastructure, and hosting costs. Specific needs driving the test year expenditures in this category include:

- Accounting and Budgeting software ($77k) – required to manage the increasing complexity and granularity of financial and regulatory requirements, and to support more detailed budgeting/forecasting on a growing capital portfolio;
- Inventory Management controls ($51k) – required to ensure the efficient and timely supply of materials to deliver BHI's growing capital portfolio without additional warehouse resources (e.g. second stockkeeper), drives efficiency through reduced stock-outs and inventory carrying costs;
- Sharepoint implementation ($49k) – necessary to create a virtual workspace for teams (including internal and external resources) to collaborate;
- Website redesign ($44k) – to deliver a modern, user-friendly, and functionally robust digital platform in compliance with AODA (WCAG 2.1 AA) standards and MFIPPA requirements to support inclusive digital access.

These investments are necessary in the Test Year to ensure that BHI's technology infrastructure remains current and resilient in response to evolving business, regulatory, and cyber security requirements. Addressing these capital investment needs enables BHI to maintain operational reliability & integrity, ensure compliance, and manage risks proactively, while also positioning itself for future growth, digitalization and technological advancements.

2-Staff-19

Reference:
Addition of previously approved ICM project to rate base
Ref 1: Exhibit 2, p. 44
Ref 2: Chapter 2 Appendices, Tab-2BA

Preamble:
The OEB approved ICM project funding of $4,762,343 from its 2025 IRM application (EB-2024-0010) related to the relocation of distribution assets as part of the Dundas St Road Widening project (from Guelph Line to Kerns Road and from Northampton Boulevard to Guelph Line). Burlington Hydro states that this project is expected to be completed by the end of 2025 and as such it has incorporated these ICM project assets into its rate base calculations and 2026 Fixed Asset Continuity Schedule.

In Chapter 2 Appendices, Tab-2AA Capital Projects includes a line item for Dundas St Road Widening - (Northampton Boulevard to Guelph line) with $2,064,473 noted for the 2026 test year.

Question(s):
a) Please confirm that Northampton Boulevard to Guelph Line section of the Dundas Street Road Widening project will be fully energized by the end of 2025. If so, please explain why the 2026 test year includes planned cost for the Dundas St Road Widening - (Northampton Boulevard to Guelph line) project. Are these additional costs and/or carryover costs?
b) Please confirm that this section of the project is still expected to be completed in 2025 and provide any updates on the progress.
c) In the Asset Continuity Schedule provided in Chapter 2 Appendices, Tab 2BA, please confirm whether the 2025 amount shown in Column G, totaling ($4,762,343), is intended to reverse or offset the corresponding amounts recorded as “Additions” in Column E in 2025.

Response:

a) The Northampton Boulevard to Guelph Line section of the Dundas Street Road Widening project is now forecast to be in service in 2026, which is why the 2026 test year includes planned costs for this work. BHI has updated its capital expenditure forecast for 2025 and 2026 in response to interrogatory 1-Staff-1 and the costs related to the Northampton Boulevard to Guelph Line section of the Dundas Street Road Widening project reflect carryover and additional costs.

b) Please see response to part a) above.

c) BHI confirms that the 2025 amount shown in Column G “ICM”, totaling $4,762,343 in Chapter 2 Appendices, Tab 2-BA is intended to reverse or offset the corresponding amounts recorded as “Additions” in Column E in 2025.

2-Staff-20

Reference:
System Renewal - Defective Equipment
Ref 1: Exhibit 2, DSP Part 1 of 3, p. 47

Preamble:
Below is a table on customer hours of interruption by cause code.

Cause Code	2020	2021	2022	2023	2024	Total CHI	%
0-Unknown/Other	5,558	2,932	386	966	732	**10,574**	**2%**
1-Scheduled Outage	2,529	8,417	6,550	34,682	17,606	**69,784**	**13%**
2-Loss of Supply	3,775	48	7,396	2,357	1,881	**15,456**	**3%**
3-Tree Contacts	22,388	6,196	12,427	25,891	47,238	**114,139**	**21%**
4-Lightning	39	5,246	70	2,255	-	**7,610**	**1%**
5-Defective Equipment	25,733	24,900	44,105	39,881	58,917	**193,537**	**35%**
6-Adverse Weather	10,115	32,324	22,246	26,762	17,095	**108,541**	**20%**
7-Adverse Environment	-	-	-	89	305	**394**	**0%**
8-Human Element	-	661	61	389	409	**1,520**	**0%**
9-Foreign Interference	1,785	5,628	11,444	4,837	10,794	**34,489**	**6%**
Total	**71,923**	**86,351**	**104,684**	**138,110**	**154,976**	**556,043**	**100%**

Question(s):

a) Burlington Hydro states that defective equipment has been the leading cause of outages for Burlington Hydro, responsible for 32% of all interruptions since 2020. Please provide a breakdown of the defective equipment outages for each year from 2020 to 2024 by equipment for customer hours of interruption.
   i. What is the frequency and scope of regular inspections for the asset classes that have the top three outage durations?
b) Given that defective equipment has consistently been the leading cause of outages by customer hours of interruption from 2020-2024, what targets or improvements does Burlington Hydro expect to achieve over the forecast period?
c) Has Burlington Hydro identified any patterns or recurring issues in the types or locations of equipment failures?

d) Given that the frequency of outages caused by defective equipment has remained relatively flat from 2020 to 2024, could Burlington Hydro explain why it is still prudent to increase spending on System Renewal during the forecast period?

Response:

a) BHI provides the defective equipment outages for each year from 2020 to 2024 by equipment for customer hours of interruption in Table 1 below.

Table 1

Equipment	2020	2021	2022	2023	2024	Grand Total
Defective Equipment - U/G Cable	5,494	11,564	14,973	14,943	5,388	52,361
Defective Equipment - Line Hardware	4,590	1,776	12,550	3,155	21,287	43,358
Defective Equipment - Transformer	4,306	4,227	2,220	5,309	5,019	21,080
Defective Equipment - Switch	8,602	596	884	6,908	2,435	19,425
Defective Equipment - Switching Cubicle		1,414	2,218	4,599	9,046	17,277
Defective Equipment - Termination	873	44	2,527	2,163	7,970	13,576
Defective Equipment - Pole	752	3,346	2,801	1,482	2,086	10,466
Defective Equipment - Insulator	590	1,185	3,296			5,072
Defective Equipment - Insulator				1,093	3,597	4,690
Defective Equipment - Arrester	33	75	2,148	18	524	2,798
Defective Equipment - Elbow	2	614	83		1,250	1,948
Defective Equipment - Secondary	451	59	406	213	317	1,445
Defective Equipment - Relay	40					40
Grand Total	**25,733**	**24,900**	**44,105**	**39,881**	**58,917**	**193,537**

i. The frequency and scope of regular inspections for the asset classes that have the top three outage durations are as follows:

1. **U/G Cable**
As part of the underground distribution assets group, U/G cables are buried infrastructure that are difficult to inspect visually as part of routine line patrols. As such BHI has incorporated a cable testing program that targets areas with ageing infrastructure with high risk and frequency of failures[1]. Cable testing results are then used to inform the DSP and prioritization under the replacement / rejuvenation program[2].

[1] EB-2025-0051, BHI DSP, p17
[2] EB-2025-0051, DSP Appendix A: Material Investment Summary Documents, p54

2. **Line Hardware**
   As part of the overhead distribution assets group, line hardware inspections are included in the annual infra-red (IR) scanning inspections that identify potential hot spots due to voltage tracking or loose connections etc. The IR report informs BHI's prioritization of replacements or repairs. Line hardware is also included in the 3-year inspection cycle through line patrols that identify visible defects/deficiencies that are immediately rectified[3].

3. **Transformers**
   Patrol inspections are scheduled every three years in accordance with the minimum inspection requirements of the DSC[4]. In addition to the minimum inspection requirements, reports are made on an ad-hoc basis when crews are working in and around transformers for other purposes, and if issues are identified, they are reported through BHIs reporting process.

b) BHI expects to achieve reliability targets based on its historical 5-year averages for actual SAIDI and SAIFI. This will require BHI to address declining reliability due to the failure of aging infrastructure through increased asset renewal and refurbishment over the forecast period. Higher System Renewal expenditures in the 2026-2030 forecast period support increased replacement of assets in Very Poor or Poor condition, as identified in BHI's ACA. This includes accelerating the pace of replacing or refurbishing underground primary cables, transformers and wood poles to mitigate failure risk and the negative impact on reliability.

   BHI is proposing to increase the number of assets replaced compared to the historical period to address the declining trend in reliability since 2021. Through its wood pole replacement program BHI plans to replace 104 poles per year to address roughly half the population of poles currently in Poor and Very poor condition over the rate period, with a further 50 poles per year reinforced through the use of PoleEnforcer as a cost-effective alternative to full replacement.

   BHI is proposing increased expenditure levels for targeted replacement of 26 km of ageing underground primary cables and aims to perform cable rejuvenation (through cable injection) on an additional 50 km over the 2026 to 2030 period. This is expected to address roughly 34% of the current population of Poor and Very Poor underground primary cables over the rate period and will help reverse the trend in number of cable faults and their impact on reliability.

[3] EB-2025-0051, BHI DSP, p59
[4] EB-2025-0051, BHI DSP, p96

c) Yes, BHI has identified recurring issues in the types and locations of equipment failures. Once the root cause is identified, a plan of action is developed in consultation with Subject Matter Experts (SMEs) to find a solution for mitigating the risk of re-occurrence. An example of a recurring failure in the past involved overhead SCADA switches, which was attributed to the location of these assets along snow routes and major highways, leading to accumulation of moisture and salt contamination. This was remedied by implementing regular monitoring, infra-red scanning, and enhancing switch maintenance frequency for this class of assets.

d) The data in Table 1 above shows that the number of customer hours of interruption due to defective equipment has increased by approximately 129% from 2020-2024. The number of customer interruptions due to defective equipment has also increased (by approx. 64%) from 2020-2024. This data supports the need and prudence of incremental investment in System Renewal.

Defective equipment is the largest contributor to the number of interruptions and customer hours of interruption and unlike other causes such as Adverse Weather, Lightning, Foreign Interference or Loss of Supply, which are caused by factor outside of the utility's control, BHI can reduce the increasing reliability risk of defective equipment outages through planned investments in System Renewal.

More than 40% of the increase in 2026 Test Year System Renewal expenditures vs. approved 2021 expenditures is inflationary, as identified in Table 2 below. To prepare this analysis, BHI applied the OEB's annual inflation factor to determine the inflation impact on System Renewal investments since the 2021 Cost of Service application. However, BHI notes that this analysis underestimates the impact of inflationary pressures observed over the current rate term as some capital costs, in particular for equipment and materials, have increased beyond the rate of inflation. For example, from 2020-2025 the average price of transformers has increased approximately 40%.

Table 2 – Impact of Inflation on System Renewal Investment Increase (2021 vs. 2026)

System Renewal	2021 CoS	2021 CoS Inflated to 2026$	2026 Test Year	2026 vs. 2021 Actuals Incr/(Decr)	Incr/(Decr) Due to Inflation	Incr/(Decr) Due to Operational Factors
	(a)	(b)	(c)	(d) = (c) - (a)	(e) = (b) - (a)	(f) = (d) - (e)
Pole Replacement Program	$1,117,942	$1,347,036	$1,581,000	$463,058	$229,094	$233,964
Underground Rebuilds	$815,152	$982,197	$2,091,000	$1,275,848	$167,045	$1,108,803
Transformer Replacement	$621,879	$749,317	$473,841	($148,038)	$127,438	($275,476)
Switch Replacement Program	$349,370	$420,965	$183,600	($165,770)	$71,595	($237,365)
Station Transformer Replacement Program	$319,004	$384,376	$408,000	$88,996	$65,372	$23,624
Switchgear Replacement Program	$292,930	$352,958	$408,000	$115,070	$60,028	$55,042
MS Feeders Cable Replacement	$223,946	$269,838	$198,900	($25,046)	$45,892	($70,938)
Replacement Substation Circuit Breakers	$117,923	$142,089	$255,000	$137,077	$24,165	$112,911
Station Relays Replacement	$115,375	$139,018	$408,000	$292,625	$23,643	$268,982
Net System Renewal	**$3,973,521**	**$4,787,793**	**$6,007,341**	**$2,033,820**	**$814,272**	**$1,219,548**
				100%	**40%**	**60%**

Beyond keeping up with inflationary pressures, the proposed increase in System Renewal investment is required to address an increasing number of assets in poor and very condition and mitigate the failure risks associated with these assets. BHI's recent ACA data shows that the condition of most asset classes has deteriorated since the 2021 ACA and will continue to deteriorate over time – replacing these assets proactively is more cost-effective, safer, and less impactful to customers' reliability than replacing reactively. Appropriately pacing these investments to prevent the further deterioration of the assets base, is prudent and necessary to avoid a future backlog of assets in need of replacement that would be difficult to manage and would jeopardize reliability, safety and environmental performance outcomes in future periods.

2-Staff-21

Reference:
Reliability
Ref 1: Exhibit 1, Part 1 of 2, p. 33

Question(s):

a) How has Burlington Hydro integrated climate risk into its asset management and investment planning processes?
b) Has the utility conducted a localized climate vulnerability assessment? If so, can it be shared?
c) What specific climate scenarios or projections were used to inform Burlington Hydro's planning?
d) Burlington Hydro states that between 2021 and 2024, Burlington Hydro experienced a 218% increase in customer outages caused by adverse weather compared to the previous four-year period (2017–2020). Can Burlington Hydro provide a breakdown of the types of adverse weather events that contributed to the 218% increase?
e) How does Burlington Hydro track and categorize weather-related outages, and how is this data used to inform investment decisions?
f) How much of the proposed investments in System Renewal is directly attributable to climate adaptation versus general asset renewal?
g) Has Burlington Hydro set any targets for reducing weather-related outages over the forecast period?
h) Burlington Hydro points to the Government of Ontario's Vulnerability Assessment for Ontario's Electricity Distribution Sector report which highlights that climate change is already significantly impacting the province. Has Burlington Hydro adopted any best practices from the Government of Ontario's Vulnerability Assessment report, and if so, which ones?
i) Please explain how Burlington distinguishes between outage codes for tree contact and adverse weather. What specific criteria or guidelines are used to classify these events?

Response:

a) BHI has integrated climate risk into its asset management and investment planning processes through various grid hardening strategies[1], asset conversions[2], and design measures[3]. Examples of this include:

- Pole replacements – assets that carry more infrastructure such as 3 phase lines, transformers and switches are prioritized over single-phase laterals.

- Transformer replacements – submersible transformer conversions in areas identified as part of Halton Region's flood plain (near creeks and identified flood areas) are prioritized over other areas

- Automated Switches – the location of these assets takes into account the exposure of lines in heavily treed areas, which enables control room operators to perform switching operations and restore power faster during extreme weather events.

b) No, BHI has not conducted a localized climate vulnerability assessment.

c) BHI has not used any specific climate scenarios or projections to inform BHIs planning, other than its historical data and publicly available information on increased extreme weather events.

d) The types of adverse weather events that contributed to the 218% increase between 2017-2020 and 2021-2024 are as follows:

- Adverse Weather – Tree Contacts (115% increase)

- Adverse Weather – Other (96% increase)

- Adverse Weather – Equipment Breakage (16% increase)

e) BHI tracks and categorizes weather events in accordance with the OEB's outage cause codes in the Electricity Reporting & Record Keeping Requirements.

f) BHI is unable to provide the requested breakdown because it does not allocate specific dollar amounts for climate adaptation versus other asset management objectives that inform capital investments. As indicated above, climate adaptation is incorporated into

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[1] DSP, p16
[2] Ibid, p18
[3] Ibid, p47

BHI's system renewal investments, as part of an integrated approach to asset management

g) No, BHI's reliability targets are based on its historical 5-year average SAIDI and SAIFI performance across all outages. BHI does not have a target for reducing weather-related outages.

h) BHI has adopted or is planning to adopt a number of best practices from the Government of Ontario's Vulnerability Assessment report, including:

- Mutual aid agreements – BHI has secured access to additional labor resources through the "Ontario Mutual Assistance Group" and agreements with contractors;
- Developed emergency planning practices that anticipate and react to extreme weather events;
- Relocating existing assets from high-risk locations (e.g. submersible transformers);
- Investing in smart grid technologies such as SCADA reclosers, switches, and sensors;
- Incorporating 'system hardening' into BHI standards (e.g. ensuring adequate storm guying and support during asset rebuilds and replacements);
- Investing in grid hardening such as pole and cable reinforcement and vegetation management; and
- Implementing monitoring regimes in order to respond quickly to major events (e.g. OMS replacement, SCADA/ADMS project).

i) BHI distinguishes between outage codes for tree contact and adverse weather in accordance with the OEB's outage cause codes in the Electricity Reporting & Record Keeping Requirements.

2-Staff-22

Reference:
Subdivisions
Ref 1: Exhibit 2 – Appendix A, p. 132

Question(s):

a) Please provide the methodology used by Burlington Hydro to determine the amount of $2.8 million per year for subdivisions.
   i. Burlington Hydro states that approximately 300 new subdivision dwelling units are forecasted to be built per year during the planning horizon. Please explain how Burlington Hydro arrives at this number.
b) Burlington Hydro states it is currently aware of 16 subdivisions at various stages of approval. Please confirm if each of the 16 subdivisions have a signed offer to connect and the expected year of each connection.
c) Please provide the number of subdivisions, subdivision units and related new connections completed to date in 2025 and forecasted for end of 2025.
d) Please provide the number of subdivisions, subdivision units and related new connections expected to be completed each year from 2026-2030.
e) Please provide a list of known subdivisions which will have connections in the 2026 test year.
f) Burlington Hydro states that the reason for variance in 2021 was due to the COVID-19 related economic slowdown. Please provide reasoning for the lack of subdivision development in 2022 and 2023.

Response:

a) BHI determined the annual amount of $2.8M for subdivisions based on the historical capital costs per subdivision unit, adjusted for inflation and the expected number of subdivision units expected over the forecast period.

   There is typically a lag between the connection of these units and BHI assuming (i.e. buying back in accordance with the OEB-prescribed transfer price methodology) these assets due to the warranty period, inspections and time taken by developers to rectify defects identified in inspections. BHI's forecasted capital expenditures are driven by the date it assumes these subdivisions, not the date they are connected.

   i. BHI arrived at the 300 new subdivision units based on the historical growth trends, Offers to Connect issued/in-progress and known developments available through the City of Burlington Site Plan Approval (SPA) process. The number of Subdivision units is an average estimate over the planning horizon.

b) BHI provides information about the 16 subdivisions including the status of the Offer to Connect and expected connection year in Table 1 below.

Table 1 – Subdivision Development – Burlington

No	Development Name	Expected number of Units	Offer to Connect (signed)	Expected Connection Year
1	2154 Walkers Line	10	Yes	2025
2	4375 Millcroft Parkway	33	Yes	3- units connected in Q1 2025; rest 2025/2026
3	D'Carlos Custom Homes	20	Yes	2025/2026
4	Bloomfield Developments	21	Yes	2025/2026
5	Stonehaven	18	No, expected in 2025	2025/2026
6	1335 – Plains Rd	30	No, expected in 2025	2026
7	2300 Queensway	24	No, expected in 2025	2026
8	Millcroft Greens	98	No, expected in 2025	2026
9	2170 Ghent Ave	21	No, expected in 2025	2026
10	Evergreen Community	907	No, expected in 2026	Undetermined (connection will take place in phases)
11	Eagle heights	924	No, expected in 2026	Undetermined (connection will take place in phases)
12	Meadowbrook Rd 2076 & 2086	28	No, expected in 2026	2027
13	GSP Group Inc	75	No, expected in 2026	2027
14	490, 496 and 508 Walkers	17	No, expected in 2025	2026
15	Aldershot- Branthaven Dev	135	No, expected in 2026	2027
16	Bronte Meadows	9000 (high level # of residential units)	No, expected in 2027	Undetermined (connection will take place in phases)

c) BHI provides the number of subdivisions, units and related new connections completed to date in 2025 and forecasted for end of 2025 in Table 2 below. The last column indicates the number of units to be assumed (buybacks) by BHI in 2025, which is what drives the forecasted capital expenditure in that year.

Table 2 – Subdivision Development – Burlington – 2025 Connections

No	Development Name	Number of Units	Number of units connected in 2025 YTD	Number of Units to be Connected by end of 2025	Number of units connected prior to 2025	Forecasted for buyback in 2025
1	2154 Walkers Line	10	10	-	N/A	-
2	4375 Millcroft Parkway	33	3	30	N/A	-
3	D'Carlos Custom Homes	20	-	20	N/A	-
4	Bloomfield Developments	21	-	21	N/A	-
5	Stonehaven	18	-	9	N/A	-
6	Bayside Crt	12	1	3	8	-
7	Sundial Alton West	325	N/A	N/A	325	325
9	2362 New Street	11	N/A	N/A	11	11
10	2100 Brant St - ROW	75	N/A	N/A	75	75
Total		**525**	**14**	**83**	**419**	**411**

d) BHI provides the number of subdivisions, units and related new connections to be completed each year from 2026-2030 in Table 3 below. See part e) for the forecasted number of units to be assumed by BHI in 2026.

Table 3 – Subdivision Development – Burlington – 2026-2030 Connections

No.	Development Name	Address	Number of Units	Number of Units Connected by 2026	Number of Units Connected by 2027	Number of Units Connected by 2028	Number of Units Connected by 2029	Number of Units Connected by 2030
1	Stonehaven	5209 Stonehaven	18	9	-	-	-	-
2	2300 Queensway	2300 Queensway	24	24	-	-	-	-
3	Millcroft Greens	2155 Country Club Dr	98	98	-	-	-	-
4	2170 Ghent Ave	2170 Ghent Ave	21	21	-	-	-	-
5	Evergreen Community	Tremaine & Dundas St	907	Undetermined at this time				
6	Eagle Heights	Flatt Road	924	Undetermined at this time				
7	490, 496 and 508 Walkers	490, 496 and 508 Walkers	17	17	-	-	-	-
8	Meadowbrook Rd 2076 & 2086	Meadowbrook Rd 2076 & 2086	28	-	28	-	-	-
9	GSP Group Inc	Old Plains Rd W 1497-1511	75	-	75	-	-	-
10	Aldershot- Branthaven Dev	Gallagher Rd	135	-	68	67	-	-
11	Bronte Meadows	Upper Middle Rd & Burloak	9,000	Undetermined at this time				
Total			**11,247**	**169+**	**171+**	**67+**	**TBD**	**TBD**

e) BHI provides a list of known subdivisions with forecasted connections in the 2026 test year in Table 4 below. The last column indicates the number of units to be assumed (buybacks) by BHI in 2026, which is what drives the forecasted capital expenditure in that year.

Table 4 – Subdivision Development – Burlington – 2026 Connections

No.	Development Name	Number of Units	Connections in 2026	Connections prior to 2026	Forecasted for buyback in 2026
1	Stonehaven	18	9	9	N/A
2	2300 Queensway	24	24	N/A	N/A
3	Millcroft Greens	98	98	N/A	N/A
4	2170 Ghent Ave	21	21	N/A	N/A
5	Evergreen Community	907	180	N/A	N/A
6	Eagle Heights	924	185	N/A	N/A
7	490, 496 and 508 Walkers	17	17	N/A	N/A
8	2154 Walkers Line	10	N/A	10	10
9	4375 Millcroft Parkway	33	N/A	33	33
10	D'Carlos Custom Homes	20	N/A	20	20
11	Bloomfield Developments	21	N/A	21	21
12	1335 – Plains Rd	30	N/A	30	30
13	3225 - 3237 New Street	10	N/A	10	10
14	1159 & 1167 Bellview Cresent	12	N/A	12	12
15	Palladium Way/Emery Business Park	10	N/A	10	10
16	2100 Brant St - Private	137	N/A	137	137
17	2384 Queensway Drive	18	N/A	18	18
Total		**2,310**	**534**	**310**	**301**

f) BHI believes that the lower level of subdivision development activity in 2022 and 2023 was primarily due to ongoing economic uncertainty and market conditions, including rising interest rates and inflationary pressures, which impacted new housing starts. In addition, many subdivision projects that were planned or approved during this period experienced delays in construction commencement. As a result, fewer subdivisions reached the stage of requiring connections during 2022 and early 2023. However, BHI observed an increase in construction activity beginning in the latter part of 2023, with corresponding subdivision connections occurring in late 2023 and continuing into 2024.

2-Staff-23

Reference:
Vehicles
Ref 1: Exhibit 2 – Appendix A, Table 5.4-7: Variance Explanations - 2025
Ref 2: Exhibit 2 – Appendix A, p. 147
Ref 3: Exhibit 2 – Appendix A, Table 5.4-14: Vehicle Replacements during Forecast Period

Preamble:
Below is a table showing the vehicle replacements during the forecast period.

Table 5.4-14: Vehicle Replacements during Forecast Period

Vehicle Classification	Vehicle Type	2026	2027	2028	2029	2030	Total
Rolling Stock (>4500 kg)	Single Bucket truck	1	1				2
	Dump Truck	1					1
	Flatbed Truck		1				1
	Radial Boom Derrick			1	1		2
	Cable Reel Trailer		1		1		2
	Equipment			1	1		2
	Single Bucket truck - Repair	1					1
Rolling Stock (>4500 kg) - Total		**3**	**3**	**2**	**3**	**0**	**11**
Rolling Stock (<4500 kg)	Pickup Truck	2	1				3
	Van	2	1				3
	Trucks/Vans/Cars		2	3	2	4	11
Rolling Stock (<4500 kg) - Total		**4**	**4**	**3**	**2**	**4**	**17**
	Total	**7**	**7**	**5**	**5**	**4**	**28**

Question(s):

a) Burlington Hydro states a cause for variance in 2025 General Plant Expenditures was higher than planned expenditures for deferred investments in large fleet vehicles. Please list the vehicles that were purchased, its cost and the in-service date.

b) Burlington Hydro is replacing 11 large vehicles over the forecast period, with zero vehicles being replaced in 2030. Has Burlington Hydro considered deferring some of these purchases to 2030?

c) Burlington Hydro is replacing 17 small vehicles over the forecast period, including 3 pickup trucks and 3 vans. Has Burlington Hydro considered reducing the pace at which new vehicle purchases are made?

d) Please provide a detailed breakdown of the Matrix Scores of all the vehicles being replaced during the Forecast Period of 2026-2030.

e) Please provide additional details regarding the type of vehicles selected to replace the existing fleet (fuel powered or electric vehicle) and the business case or analysis used to determine the lowest cost options for Burlington Hydro.

f) Burlington Hydro states in 2024, Trucks 23 and 24 were out of service for a combined eight weeks, it further states that out of service vehicles place undue strain on the operations group to keep appointments and to maintain service levels for customers. Please provide a detailed explanation of the impact on the operations group and the effects on service levels for customers.

g) Which specific vehicles, and their associated cost, are to be replaced in each of the 2026-2030 forecast years? Will the old vehicles be put out of service upon the arrival of their replacement?

h) Please confirm what year the bucket trucks will be put into service.

Response:

a) BHI purchased one large fleet vehicle in 2025 – a Radial Boom Derrick (RBD). The total cost of this RBD is $583,750 and is expected to be in-service by Sept.1st, 2025. Note that in 2025, BHI also purchased a chassis for another bucket truck which is to be assembled and planned to be delivered in 2026.

b) No, BHI has not considered deferring some of these purchases to 2030 as it relies on its Fleet Management Plan to identify, prioritize and pace vehicle replacements based on the matrix score categories.

   BHI is planning to replace/repair 7 large vehicles, 2 trailers and 2 equipment vehicles over the forecast period in accordance with its Fleet Management Plan. Deferring additional replacements to 2030 is not considered prudent at this time, as further delays could result in vehicles becoming unreliable or inoperable, leading to increased maintenance costs, potential service disruptions, and higher total lifecycle costs. Therefore, the planned timing reflects a necessary balance between asset condition, operational risk, and financial stewardship.

   The replacement schedule has already been paced over multiple years to balance operational needs and cost-effectiveness — for example, bucket trucks and RBD vehicles have been scheduled for replacement in different years to avoid service disruptions.

c) No, BHI has not considered reducing the pace at which the new vehicle purchases are made as it relies on its Fleet Management Plan to identify, prioritize and pace vehicle replacements based on the matrix score categories.

BHI is replacing 17 small vehicles over the forecast period in accordance with its Fleet Management Plan. The replacement schedule has already been paced over multiple years to balance operational needs and cost-effectiveness. Any further reduction in the pacing at which the new vehicle purchases are made is not considered prudent at this time, as further delays could result in vehicles becoming unreliable or inoperable, leading to increased maintenance costs, potential service disruptions, and higher total lifecycle costs. Therefore, the planned timing reflects a necessary balance between asset condition, operational risk, and financial stewardship.

d) BHI provides a detailed breakdown of the Fleet Elevation Matrix scores (higher score correlates to poorer condition of vehicle) of all vehicles being replaced during the forecast period of 2026-2030 (excluding those listed in Table 1) based on the most recent evaluation conducted in 2024 in IR_Attachment_2-Staff-23d_BHI_07242025.

BHI has included additional information in the attachment to satisfy its response to interrogatory 2-Intervenor-73 b).

Please see BHI's response to part g) of this interrogatory response for a reference of unit numbers to specific vehicles (e.g. unit # T23 is "International 46'") for 2026-2030 replacements.

For Trailers and equipment (units T94, T97, T90 and T96), in the absence of a mileage reader, BHI considers their repair/refurbishment based on age, service history, and current condition. BHI provides Table 1 below with service age and condition of these assets.

Table 1

Vehicle	Type	Year of Purchase	Service age	Condition
Cable Reel Trailer Single - refurbished	Cable Reel Trailer	1998	26	Fair - continue to monitor
Cable Reel Trailer - refurbised	Cable Reel Trailer	1995	29	Fair - continue to monitor
Altec DB35 Digger Derrick	Equipment	2006	18	Fair - continue to monitor
John Deere 310SE	Equipment	2001	23	Fair - continue to monitor

e) BHI determines the fuel type (fuel powered or electric vehicle) based on the operational needs of the business, in addition to considerations such as cost, business purpose, and vehicle range (for electric vehicles). This determination is made at the time of vehicle replacement. For the forecast period, BHI has not yet determined the fuel type or conducted analysis for the vehicles planned for replacement, with the exception of the bucket truck scheduled for replacement in 2026.

For 2026, BHI has placed an order for a chassis for a bucket truck (fuel powered) with POSI+ in accordance with BHI's purchasing policy. BHI typically replaces its large vehicles from POSI+. These vehicles are highly specialized utility type vehicles that have various functionalities for safe and efficient day-to-day operations. BHI's staff is familiar with all the functionalities of these vehicles, and it plans to continue to use the same arrangements and layouts of the large vehicles within the BHI Fleet. That way BHI will maintain staff familiarity with the vehicles and avoid any potential delays with execution of the work and more importantly potential unfamiliarity with the abilities of the vehicles that may lead to unsafe operating conditions.

f) Trucks 23 and 24 are equipped with 46-foot booms and are considered essential 'workhorses' within BHI's large fleet. These vehicles have some of the highest mileage, approaching 200,000km driven. Due to their size and maneuverability, they are frequently deployed by BHI crews to respond to both planned and unplanned work, particularly in dense urban areas with rear-lot services as well as in rural areas with narrow roadways. When those two trucks are out of service at the same time, BHI must rely on alternative vehicles such as Truck 21 or Truck 30. However, Truck 21 has a shorter boom, which limits its reach, while Truck 30 has a significantly larger boom, making it unsuitable for tight or restricted access locations. This operational constraint negatively impacts BHI's ability to maintain expected service levels and respond promptly to customer needs. Ensuring the availability of appropriately sized and capable trucks is therefore critical to supporting reliable and efficient field operations.

g) BHI provides details of specific vehicles planned for replacement over the 2026-2030 forecast period and their associated cost in Table 2 below. Further, BHI confirms that the old vehicles that are being replaced are immediately taken out of service.

Table 2

Vehicle	Unit #	2026 Test Year	2027	2028	2029	2030
Large						
International Digger Derrick	T35	$408,000	$0	$0	$0	$0
Ford F650 Cab & Chassis Dump	T31	$102,000	$0	$0	$0	$0
Ford F350 Cab & Flatbad	T32	$0	$46,800	$0	$0	$0
International Digger Derrick	T34	$157,080	$416,000	$0	$0	$0
International 46'	T24	$0	$160,160	$329,971	$0	$0
International 46'	T23	$0	$0	$163,394	$336,502	$0
Freightliner M2 46' Single Bucket - repair	T22	$51,000	$0	$0	$0	$0
Cable Reel Trailer Single - refurbished	T94	$0	$36,400	$0	$0	$0
Cable Reel Trailer - refurbised	T97	$0	$0	$0	$21,640	$0
Altec DB35 Digger Derrick	T90	$0	$0	$0	$162,300	$0
John Deere 310SE	T96	$0	$0	$47,745	$0	$0
Total Large		**$718,080**	**$659,360**	**$541,110**	**$520,442**	**$0**
Small						
Ford F150	T13	$68,340	$0	$0	$0	$0
Chev Express	T37	$86,700	$0	$0	$0	$0
Chev Express	T38	$86,700	$0	$0	$0	$0
Dodge Ram	T43	$61,200	$0	$0	$0	$0
Dodge Ram	T17	$0	$69,680	$0	$0	$0
Mercedes Sprinter	T79	$0	$88,400	$0	$0	$0
Vans/Pick-up Trucks/Cars (undetermined)*	Various	$0	$83,200	$193,102	$164,464	$256,128
Electric Vehicles Chargers	N/A	$10,200	$10,400	$10,610	$0	$11,040
Total Small		**$313,140**	**$251,680**	**$203,712**	**$164,464**	**$267,168**
Total Vehicles		**$1,031,220**	**$911,040**	**$744,822**	**$684,906**	**$267,168**

**While most of the vehicles are identified and planned for replacement, there are some vehicles for which exact timing of replacement is undetermined at this time. BHI will monitor the condition of these vehicles (units T45, T46, T47) and determine their replacement timeline (2027-2030) based on the results of its Fleet Evaluation Matrix in those years.*

h) BHI confirms the year the new bucket trucks will be put into service as follows:

- Unit # T35 replacement is expected to be put into service in 2026.
- Unit # T34 replacement is expected to be put into service in 2027.
- Unit # T24 replacement is expected to be put into service in 2028.
- Unit # T23 replacement is expected to be put into service in 2029.

2-Staff-24

Reference:
Miscellaneous
Ref 1: Chapter 2 Appendices – Tab AA, Capital Projects

Question(s):

a) Please provide a breakdown of the costs for building upgrade costs by individual projects. If applicable, please identify if each project relates to any of the recommended repairs from the 2021 building condition assessment (pages 5-6, Table 1).
b) The proposed capital expenditure for the 2026 test year is $871k, $431k or 98% higher compared to the average annual spend of $441k forecasted for 2027 to 2030. Please explain why Burlington Hydro is unable to defer a portion of the proposed 2026 spending to later years in order to smooth out planned capital costs over the forecast period.
c) In Table 5.3-14, Burlington Hydro states that only 13% of buildings are in poor condition, and 38% are in fair condition. Please confirm the condition of all the buildings projects it plans to work on.
d) Burlington Hydro states that its previous spending of $330,000 per year is inadequate and unsustainable for addressing the needs of its aging facilities. Please describe in detail the changes between the historical and forecast period which can account for this.
e) Burlington Hydro states renovations and upgrades include the addition of new offices and workstations to accommodate new Full-Time Equivalent requirements. Please provide the current square footage per employee and detail if the changes being made will affect this number.
f) Please explain the need and prudence to upgrade the visitor parking lot from ~3,500sqft to 20,000sqft given that the main head office parking lot is currently ~37,000sqft. How many parking spaces are currently in the main and visitor lots respectively? How many parking spaces will be added to the main and visitor lots respectively?
g) Please confirm how many of the 40 HVAC units Burlington Hydro considers to be at, or approaching, the end of their useful lives. What does is the useful life Burlington Hydro uses for HVAC units? Please provide the asset condition for each of the HVAC units and confirm which ones are planned for replacement in the forecast period.

Response:

a) BHI provides a breakdown of the building upgrade costs by individual project for 2026-2030, including identification of projects related to recommended repairs from the 2021 building condition assessment in Table 1 below. BHI included the 2026 priority ranking of each project in response to 2-Intervenor-71 a) as well as a description of the scope of the project as additional information.

Table 1

Program	Included in building condition assesment	Priority Ranking 2026	2026 Test Year	2027	2028	2029	2030	Description
1340 Brant St.	Yes	13	$275,400	$239,200	$265,250	$162,300	$165,600	Includes sections of roof repairs, foundation repairs and windows replacements etc.
[redacted]	[redacted]	21	$234,600	$0	$0	$0	$0	[redacted]
[redacted]	[redacted]	24	$66,300	$10,400	$10,610	$10,820	$11,040	[redacted]
Parking lot	Yes (North parking lot), South parking lot based on needs assesment	44	$127,500	$124,800	$127,320	$0	$0	Includes asphalt resurfacing and repairs to BHI's head office North parking lot and expansion of visitor (South) parking lot
1328 Brant St. MS building	No, as per Asset Condition Assesment report	36	$10,200	$10,400	$10,610	$10,820	$11,040	General capital repairs and maintenance
Distribution Stations	No, as per Asset Condition Assesment report	26	$24,480	$24,960	$31,830	$32,460	$33,120	Includes renovation/repair of exterior of two MS buildings per year
HVAC System	Yes (partial), remaining based on needs assesment	18	$81,600	$83,200	$84,880	$86,560	$44,160	Includes two HVAC units replacement per year
1340 Brant St. Upgrades	No, based on needs assesment	33	$51,000	$52,000	$53,050	$32,460	$33,120	Includes renovations and upgrades of new/existing offices and workstations
Total			**$871,080**	**$544,960**	**$583,550**	**$335,420**	**$298,080**	

b) BHI has already deferred portions of the planned capital costs for Buildings to later years in the forecast period based on customer feedback in its customer engagement activities[1].

BHI provides a comparison of its planned capital costs for Buildings that underpinned its customer engagement[2] and the plan submitted for this Application[3] in Table 2 below. BHI smoothed its roof rehabilitation project and parking lot paving over the 2026-2028 period.

Table 2

Program	2026 Test Year	2027	2028	2029	2030
Buildings - per customer engagement	$1,268,880	$305,760	$350,130	$335,420	$298,080
Buildings - per the Application	$871,080	$544,960	$583,550	$335,420	$298,080
Difference	($397,800)	$239,200	$233,420	$0	$0

c) Table 5.3-14 of the DSP only includes an asset condition for BHI's Municipal Stations (MS) buildings. The condition of its 1340 Brant St. (head office) building is separately assessed in the 2021 Building Condition Assessment[4]. The report did not assign an overall condition rating to the building but rather evaluated individual components (e.g., roof, foundation, windows, mechanical systems, etc.) and provided recommendations based on the observed condition of each. BHI has included the 1340 Brant St. building

[1] Page 24 of the DSP
[2] Section 1.5.3 of Exhibit 1
[3] Chapter 2 Appendices 2-AA
[4] DSP : Appendix O

project in its forecast based on the findings and recommendations of this assessment. Please also refer to BHI's response to part a) of this interrogatory for further details. With respect to MS buildings, over the forecast period, BHI plans to recondition a total of eight buildings — four of which are in poor condition and four in fair condition, as defined in Table 5.3-14.

d) BHI describes the changes between the historical and forecast period which are driving the need for increased investment in its head office building as follows:

- 1340 Brant St. ($133k higher average per year) – historically, BHI's approach to maintaining its 60-year-old head office building was limited to addressing immediate needs or performing reactive repairs. In 2023, BHI was required to replace a section of the leaking roof on an emergency basis, which disrupted operations and resulted in significant unplanned costs. This experience highlighted the unsustainability of a reactive maintenance approach. Accordingly, BHI has adopted a more proactive strategy informed by the findings of the 2021 Building Condition Assessment[5], which identified necessary work on major building components such as the roof, foundation, and windows. The forecasted spending reflects this shift toward planned rehabilitation to support reliable operations and long-term cost control.

[redacted]

- Parking lot ($69k higher average per year) – the increased spending is driven by two factors: (1) paving and resurfacing of the North parking lot, which was recommended in the 2021 Building Condition Assessment; and (2) expansion of the South parking lot, which is based on a needs assessment.

Please refer to the DSP[6] for further details.

e) The current average workspace ranges from 50 sq.ft to 120 sq.ft depending on the role and needs of the staff. It is undetermined at this time if the changes being made will affect these averages.

[5] ibid
[6] Page 91 of Appendix A

f) Currently, BHI's main parking lot contains 105 spaces, including 2 accessible spaces and 2 electric vehicle (EV) charging spaces. The visitor parking lot has 16 spaces, including 2 accessible spaces and 2 EV charging spaces.

BHI plans to asphalt/repair the main parking lot with an increase in one accessible space and reduction in two spaces. Further, the visitor parking lot will be expanded from approximately 3,500 sq. ft. to 20,000 sq. ft., adding 60 new spaces.

The expansion of the visitor lot is driven by the need to accommodate increased visitors, contractors/vendors, and additional staff to BHI's head office. BHI updated its internal policy to require all non-employee personnel to use the visitor parking lot and the South entrance to help maintain appropriate safety and security protocols.

g) Currently, 22 of the 40 HVAC units are at or approaching their end of useful life by 2030. Depending on the type of equipment, the useful life ranges from 15 to 25 years. An external asset condition assessment of all HVAC units has not been performed, hence BHI is not able to provide the asset condition for each of the HVAC units. However, planned replacements are driven by the 2021 Building Condition Assessment, internal inspections, age and increasing repair and maintenance costs. HVAC units to be replaced over the forecast period are provided in Table 3 below.

Table 3

Equipment Name
RTU 2
RTU 5
RTU 8
RTU 11
RTU F2
RTU 4
RTU 6
Split System (6Ton)
EF 1
EF 2
EF 3
EF 4

2-Staff-25

Reference:
Miscellaneous
Ref 1: Chapter 2 Appendices – Tab AA, Capital Projects

Question(s):

a) Please explain the miscellaneous line item, including what this budget is comprised of and how it is estimated.

Response:

a) The miscellaneous line in the Chapter 2 Appendices – Tab AA includes projects and programs which are below BHI's materiality threshold of $242,000. BHI provides the breakdown of the programs/projects included under the miscellaneous line in Table 1 below.

BHI has updated its 2025 and 2026 capital expenditures in response to interrogatory 1-Staff-1 and the below table reflects the updated forecast for 2025 and 2026.

Table 1

Program	2021	2022	2023	2024 Actual	2025 Bridge Year	2026 Test Year	2027	2028	2029	2030
Office Equipment	$0	$10,994	$40,279	$0	$22,940	$20,400	$46,800	$29,178	$21,640	$35,328
Tools	$23,042	$63,034	$25,400	$29,332	$70,000	$20,400	$20,800	$21,220	$21,640	$22,080
Ammeters/Meter shop console	$0	$0	$0	$1,402	$19,228	$40,800	$10,400	$10,610	$10,820	$11,040
Primary Metering Tank Replacement	$24,911	$16,455	$9,865	$7,794	$70,000	$107,100	$78,000	$79,575	$81,150	$82,800
Reactive Replacement (OH)	$64,403	$106,861	$18,779	$58,439	$50,290	$0	$0	$0	$0	$0
Recommission Substations	$48,725	$29,886	$40,909	$3,237	$0	$0	$0	$0	$0	$0
Metalclad Equipment Refurbish/Paint	$0	$3,661	$1,679	$0	$0	$20,400	$20,800	$21,220	$21,640	$22,080
Upgrade RTUs Scouts	$27,875	$39,132	$34,741	$25,000	$30,000	$30,600	$31,200	$31,830	$32,460	$33,120
Battery Banks & Chargers	$22,871	$15,975	$9,365	$19,894	$5,000	$10,200	$10,400	$10,610	$10,820	$11,040
Transducers	$103	$4,475	$5,321	$0	$0	$5,100	$5,200	$5,305	$5,410	$5,520
Total	**$211,928**	**$290,473**	**$186,338**	**$145,098**	**$267,458**	**$255,000**	**$223,600**	**$209,548**	**$205,580**	**$223,008**

BHI provides the basis of estimation of these projects/programs for the forecast period (2026-2030) in Table 2 below.

Table 2

Program	Basis of estimation
Office Equipment	Based on needs assessment
Tools	Based on needs assessment
Ammeters/Meter shop console	Based on needs assessment
Primary Metering Tank Replacement	Based on needs assessment
Reactive Replacement (OH)	Reactive
Recommission Substations	N/A
Metalclad Equipment Refurbish/Paint	Based on needs assessment
Upgrade RTUs Scouts	Based on historic values
Battery Banks & Chargers	Based on needs assessment
Transducers	Based on needs assessment

2-Staff-26

Reference:
Loss Factors
Ref 1: Exhibit 8, p. 15
Ref 2: Exhibit 8, Appendix C
Ref 3: Chapter 2 Appendices, Tab 2-R – Loss Factors
Ref 4: EB-2020-007, Chapter 2 Appendices, Tab 2-R – Loss Factors

Preamble:
Below are loss factor in the distributor's system from 2015- 2024:

	2015	2016	2017	2018	2019	5-Year Average
Loss Factor in Distributor's system	1.0324	1.0323	1.0347	1.0366	1.0393	1.0350

	2020	2021	2022	2023	2024	5-Year Average
Loss Factor in Distributor's system	1.0403	1.0393	1.0360	1.0390	1.0388	1.0387

Question(s):

a) Please explain the factors contributing to the increase in the distribution system loss factor from 1.035 approved in the 2021 cost of service application to 1.0387 in the current application.
b) Burlington Hydro states that the year-over-year fluctuation in loss factors is due to the composition of Burlington Hydro's distribution network, which operates across three distinct voltage systems: 27.6kV, 13.8kV, and 4.16kV.
    i. Has Burlington Hydro conducted any scenario analysis to estimate how the loss factor would change if the 4.16kV system were fully converted to 27.6kV?
    ii. Does Burlington Hydro have any long-term plans for converting the remaining 4.16kV and 13.8kV systems to 27.6kV?
c) Based on the line loss mitigation projects completed to date and Burlington Hydro's current plan for future loss reduction initiatives, what is Burlington Hydro's forecast for the average distribution system loss factor over the next five years (2025-2029)?
    i. Please indicate whether the forecasted loss factor is expected to decline, stabilize, or increase, and explain the key drivers influencing the trend.

Response:

a) Factors contributing to the increase in the distribution system loss factor from 1.035 approved in the 2021 cost of service application to 1.0387 in the current application include higher customer connections on the 4.16kV system. The 4.16kV system continues to be incrementally loaded at or near its maximum allowable capacity, leading to higher losses, primarily due to customer-driven new connections being served through this voltage.

b)

i. No, BHI has not conducted any scenario analysis to estimate how the loss factor would change if the 4.16kV system were fully converted to 27.6kV.

ii. BHI does not have any specific plans to convert 4.16 kV or 13.8 kV stations to 27.6 kV. However, other drivers may result in a decision to convert. For example, an upgrade of infrastructure to 27.6 kV to accommodate a system expansion or connection of new customer(s) may present the opportunity to convert to 27.6 kV.

c) BHI's past and future line loss reductions are ancillary benefits of other projects being completed for other system reasons (e.g. to manage failure risk, modernize the grid). As such, BHI expects that its loss factor will stabilize over the forecast period.

<u>2-Staff-27</u>

Reference:
Fixed asset - Capitalization
Ref 1: Exhibit 1, Appendix G – 2024 Audited Financial Statements, Note 7, p.103
Ref 2: Exhibit 2, Section 2.2, Fixed asset continuity schedule
Ref 3: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.2.2, p.18

Preamble:
In Ref 1, Burlington Hydro states that no interest was capitalized to property, plant and equipment (PP&E) during the year.

In Ref 2, Burlington Hydro states that it does not capitalize interest during construction.

In Ref 3, Chapter 2 Filing Requirements states that:

“Continuity statements must provide year-end balances and include any capitalized interest during construction and any capitalized overhead costs.”

Question(s):

a) Please explain why Burlington Hydro does not capitalize any interest during construction.

b) Please also clarify how Burlington Hydro treats the interests during construction in the rates.

c) Please update and resubmit Chapter 2 Appendices as applicable.

Response:

a) BHI does not capitalize interest during construction in accordance with IFRS (IAS 23 – Borrowing Costs). The standard applies to borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset. Qualifying assets are defined as assets that take a substantial period of time to get ready for their intended use or sale. BHI’s assets do not meet the definition of a qualifying asset, nor are the borrowing costs directly attributable to the acquisition, construction or production of that asset. BHI does have debt but the interest costs associated with that debt cannot be directly attributed to a specific asset.

b) BHI expenses interest on long-term debt in USoA 6605 which is not included in any components of revenue requirement, and as such interest during construction is not specifically included in rates. Rates include deemed interest, in accordance with the OEB Chapter 2 Filing Requirements.

c) No update is required.

2-Staff-28

Reference:
Fixed asset – Service life
Ref 1: Chapter2Appendices_2BB_Service Life_04162025, Table F-2
Ref 2: EB-2020-0007, Settlement_Attachment_Main_OEB_Chapter2Appendices_20210317, 2-BB, Table F-2
Ref 3: Kinectrics Report (July 8, 2010), Table F, p.17~19
Ref 4: Exhibit 2, Section 2.4.1-Depreciation/Amortization Policy, p.27
Ref 5: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.2.4, p.20

Preamble:
In Ref 1, OEB staff has compiled Table (A) for certain assets as below, showing the useful lives are outside of the typical ranges outlined in Ref 3.

Table (A): Comparation of Useful Lives

Parent #	#	Asset Details	UsoA	MAX UL (Kinetrics)	Proposed	Variance
TS & MS	15	Station DC System-Battery Bank	1820	15	20	5
UG	25	Primary Ethylene-Propylene Rubber (EPR) Cables	1845	25	40	15
UG	26	Primary Non-Tree Retardant (Non-TR) Cross Linked	1845	30	40	10
UG	27	Primary Non-TR XLPE Cables in Duct	1845	30	40	10
UG	31	Secondary Cables Direct Buried	1855	40	60	20
	2	Vehicles-Vans	1930	10	12	2
	6	Computer Equipment-Software	1611	5	5-10	0-5

OEB staff notes the proposed useful lives of the assets identified in Table (A) above are not within the ranges contained in the Kinectrics Report in Ref 3.

Per Ref 1 & 2, OEB staff has compiled Table (B) as below, showing the difference of useful life of UsoA 1611 Computer Software between what was approved in last COS (EB-2020-0007) and what is included in the current application.

Table (B) Comparation of Useful Life and Depreciation Rate of UsoA 1611

	Useful Life	Rate
Ref 1-Current Application	5-10	0%
Ref 2-Last Application	5	20%

OEB staff notes that Burlington Hydro indicates 0% depreciation rate for Account 1611 per Table (B) above.

In Ref 4, Burlington Hydro states that there was an error of UsoA 1611 service life in last COS which indicated 5 years. It should have indicated a service life of 5-10 years since assets in this account that are depreciated over 10 years, specifically its GIS and CIS.

OEB staff notes the typical service life of computer software per Ref 3 is maximum 5 years.

Chapter 2 Filing Requirements states:

> *"Distributors must also provide explanations and support for any proposed useful lives that are not within the ranges contained in the Kinectrics Report."*

Question(s):

a) Please provide the rational of why the proposed service life is outside of the typical ranges outlined in Ref 3 identified in Table (A) above.
b) Please explain why the depreciation rate of UsoA 1611 is 0% per Table (B) in this application and update the depreciation rate of UsoA 1611 as applicable.
c) Please quantify the revenue impact of the service life change Burlington Hydro made for UsoA 1611 per Table (B) above in the following format using updated depreciation rate of b) above.

	2026 Test Year Capital Additions	2026 Test Year Accumulated Depreciation Additions	Amount included in Revenue requirement (RRWF)
5-10 years at XX% (Ref 1)			
5 years at 20% (Ref 2)			
Variance			

Response:

a) With the exception of Computer Software, BHI's proposed service lives in its Application were approved by the OEB in BHI's 2014 Cost of Service application (EB-2013-0115) and again in BHI's 2021 Cost of Service application (EB_2020-0007). The asset useful lives, for the distribution system assets identified in Table (A), were derived from a Kinectrics Report conducted specifically for BHI in conjunction with Enersource, Oakville Hydro, Milton Hydro and Halton Hills Hydro ("the Report"). For ease of reference the Report, which includes rationale for the approved useful lives, is filed as Appendix 2-Staff-28 a). The Report was filed and approved by the OEB in BHI's 2014 Cost of Service application (EB-2013-0115)[1].

   Vehicles (Vans – USoA 1930) are depreciated over 12 years as compared to the maximum useful life of 10 years as it is BHI's experience that these assets are used, and have longer service lives, than 10 years.

   Most computer software is depreciated over 5 years. However BHI's new CIS and GIS are depreciated over 10 years. BHI does not typically replace these systems after 5 years, and uses them for 10 years before replacement. For example, BHI's new CIS was implemented in July 2021 and BHI has no plans to replace this system during the 2026-2030 rate term.

b) The depreciation rate was erroneously calculated as 0% in the Chapter2Appendices_2BB_Service Life_04162025, Table F-2. BHI updates Appendix 2-BB in Attachment_OEB_Chapter2Appendices_BHI_07242025 to reflect a depreciation rate of 10-20% which is dependent on whether the Computer Software has a useful life of 10 years (CIS, GIS) or 5 years (all other).

[1] EB-2020-0007, Exhibit 4, page 199

c) BHI provides the requested information in Table 1 below.

Table 1 - Revenue Impact of the Service Life Change for UsoA 1611

USoA 1611 (CIS and GIS)	Cumulative Test Year Capital Additions	Cumulative Test Year Accumulated Depreciation	Amount Included in Revenue Requirement 2026 Test Year
5 yrs at 20% in 2021 and 10 yrs at 5% in 2022-2026 (Ref 1)	$5,308,751	$3,429,987	$594,438
5 years at 20% (Ref 2)	$5,308,751	$5,211,156	$247,621
Variance	**$0**	**($1,781,170)**	**$346,817**

2-Staff-29

Reference:
Depreciation
Ref 1: Chapter2Appendices_2C_DepExp_04162025

Preamble:
Per Ref 1, OEB staff has compiled Table (C) as below, showing that there are two accounts drove the most depreciation variance for both 2025 and 2026.

Table (C) Accounts with significant variances from 2025 to 2026

Account	Description	2025 Variance (Ref 1)	2026 Variance (Ref 1)
1820	Distribution Station Equipment <50 kV	43,798	49,632
1920	Computer Equipment - Hardware	58,479	53,633
Total		**102,277**	**103,265**

Question(s):

a) Per Table (C), please elaborate why there is significant variance for the two accounts identified above.

Response:

a) BHI has identified an error in the calculation of the depreciation in the 2025 Bridge and 2026 Test Years for USoA 1820, where it effectively used a service life of greater than 40 years to calculate depreciation. This has resulted in the variances identified in Table (C) above. As the resulting differences are below BHI's materiality threshold, BHI does not propose to make any adjustments to the depreciation for this account.

BHI reviewed the calculation of depreciation for Account 1920 and identified that the amounts shown in column "Less Fully Depreciated" for 2025 and 2026 in Chapter 2 Appendices Tab App. 2-C were incorrect. BHI has corrected these amounts and as a result, the variance has been significantly reduced to $4,793 in 2025 and $3,193 in 2026. Please see the updated Attachment_OEB_Chapter2Appendices_BHI_07242025 Tab App. 2-C.

2-Staff-30

Reference:
Fixed asset - ICM
Ref 1: Chapter2Appendices_2BA_Fixed Asset Cont_04162025
Ref 2: Settlement_Attachment_Main_OEB_Chapter2Appendices_BHI (EB-2020-0007), 2BA_Fixed Asset Continuity Schedule

Preamble:
Per Ref 1 & Ref 2, OEB staff complied the Table (D) as below, showing the difference of accumulated depreciation of Account 1609 Capital Contributions Paid (CCA Class 14.1) between the last Cost of Service application and this application.

Table (D) Variance of Accumulated Depreciation of Account 1609

	Cost-ICM	Accumulated Depreciation
Ref 1	$2,568,000	($85,600)
Ref 2	$2,568,000	($128,400)
Variance	**0**	**$42,800**

Question(s):

a) Please explain the variance identified in Table (D) above.

b) Please provide breakdown of what ICM project cost was included in Account 1609.

c) Please explain why there was no corresponding assets amounts recorded in the ICM column of 2BA for Ref 1 in 2021?

Clarification: $2,568,000 is recorded in Account 1609 which is capital contribution paid. OEB Staff is asking whether there were any actual assets constructed of that ICM in 2021, provided that BHI received this $2.5M capital contribution of the ICM project. If yes, where were those assets recorded? Why were these assets not recorded in the ICM column in 2021?

Response:

a) In Reference 1, BHI included the 2021 depreciation of the ICM assets of $42,800 in the Accumulated Depreciation – Additions column in error. BHI has corrected the Accumulated Depreciation for ICM asset to show ($128,400) in the updated Tab 2-BA in Attachment_OEB_Chapter2Appendices_BHI_07242025.

b) BHI provides a breakdown of the ICM project costs included in Account 1609 in Table 1 below.

Table 1

Description	Tremaine TS CCRA True-up	Tremaine TS Additional Breakers CCRA	Total
ICM project cost	$568,000	$2,000,000	$2,568,000

c) BHI did not need to record any assets in the ICM column of any other USofA account as costs paid under a Connection and Cost Recovery Agreement (CCRA) are recorded in UsoA 1609 Capital Contributions Paid as per the Accounting Procedures Handbook for Electricity Distributors[1]. BHI paid capital contributions to Hydro One to access transmission capacity at Hydro One at Tremaine Transmission Station (TS). The transmission assets at the Tremaine TS are owned, operated and maintained by Hydro One and they would typically record the assets in their continuity schedule.

[1] Page 42 of Accounting Procedures Handbook for Electricity Distributors issued on January 1, 2012

3-Staff-31

Reference:
COVID-19
Ref. 1: Exhibit 3, p. 69

Question(s):

a) Did Burlington Hydro test for COVID-19 as an explanatory variable in its regression analysis of the Residential, GS<50kW and GS>50kW classes? If so, please provide the results. If not, please explain why.

Response:

a) The COVID-19 variable was tested as an explanatory variable in the regression analysis in the development of the load forecast, however, it was not re-tested after actual full year 2024 load, customer, and economic data was available. Please refer to BHI's response to 3-Intervenor-84, 3-Intervenor-85 and 3-Intervenor-86 for the results.

3-Staff-32

Reference:
Ref. 1: Exhibit 3, p. 74

Question(s):

a) Please provide the customer numbers and consumption for the most recent historical months for 2025.

b) When is the GS>50 kW customer expected to fully cease operations? Please also explain the general decreases in this class's customer counts.

Response:

a) Please refer to Attachment_Load_Forecast_Model_BHI_07242025.

b) The GS<50kW customer ceased operations on April 30, 2025. The general decreases in this class's customer counts are attributable to rate reclassifications from the GS>50 kW rate class to the GS<50 kW rate class, due to lower demand. A net 34 customers were reclassified from the GS>50 kW rate class to the GS<50 kW rate class from 2020 to 2024.

3-Staff-33

Reference:
Ref. 1: Exhibit 3, p. 74

Preamble:

Burlington Hydro states, “The allocation of incremental consumption to rate class is estimated based on judgement as BHI does not have these details by rate class. The allocations and allocated incremental consumption by EV type to each rate class is provided in Table 28.”

Question(s):

a) Please explain this allocation by rate class based on judgement.

Response:

a) The allocation of EV consumption was determined by Power Advisory and BHI, and was informed by factors such as the number of customers in each rate class, Power Advisory’s experience with other LDCs, and BHI’s assessment of EV uptake by type of customer.

3-Staff-34

Reference:
Ref. 1: Exhibit 3, p.19- 26

Question(s):

a) Did Burlington Hydro test for colinear independence between Ontario Economic Accounts GDP and customer count as well as Ontario Economic Accounts GDP change and customer count for the GS<50 kW rate class? If not, please do so.

b) Did Burlington Hydro test for colinear independence between Toronto FTE and trend as well as Toronto FTE change and trend for the GS>50 kW rate class? If not, please do so.

c) Please provide the results of the tests for colinear independence between the economic variables and the trend variable.

d) As a scenario, please provide a regression where trend variable is not used.

Response:

a) No, BHI did not directly test for colinear independence between Ontario Economic Accounts GDP and customer count or the Ontario Economic Accounts GDP change and customer count for the GS<50 kW rate class. However, the statistical results for the model showed autocorrelation through the Durbin-Watson statistic so the Ontario Economic Accounts GDP variable was replaced with the Ontario Economic Accounts GDP Change variable. The correlation between Ontario Economic Accounts GDP and GS<50 kW customer count is 0.895, indicating a high level of correlation. The correlation between Ontario Economic Accounts GDP change and GS<50 kW customer count is 0.012, indicating a low level of correlation.

b) No, BHI did not directly test for colinear independence between Toronto FTE and trend or Toronto FTE change and trend for the GS>50 kW rate class. However, the statistical results for the model showed autocorrelation through the Durbin-Watson statistic so the Toronto FTEs variable was replaced with the Toronto FTE Change variable. The correlation between Toronto FTE and the trend variable is 0.867, indicating a high level of correlation. The correlation between Toronto FTE change and the trend variable is 0.137, indicating a low level of correlation.

c) The correlation between the trend variable and each economic variable is provided in Table 1 below.

Table 1

Economic Variable	Total Variable	Change Variable
Ontario FTEs	0.847	0.18
Toronto FTEs	0.867	0.137
Hamilton FTEs	0.658	-0.037
Ontario GDP (Statistics Canada)	0.949	0.009
Ontario Services GDP (Statistics Canada)	0.954	0.043
Ontario Professional Services GDP (Statistics Canada)	0.964	0.194
Ontario GDP (Ontario Economic Accounts)	0.926	0.001
Ontario Services GDP (Ontario Economic Accounts)	0.9368	0.02
Ontario Transportation & Warehouse GDP (Ontario Economic Accounts)	0.0455	0.068

d) The regression without a time trend variable is provided in Table 2 below.

Table 2

Model 1: Prais-Winsten, using observations 2015:01-2024:12 (T = 120) Dependent variable: GS_gt_50_NoCDM rho = 0.866543				
	coefficient	std. error	t-ratio	p-value
const	8,694,573	3,609,541	2.41	0.018
HDD10	18,312	1,590	11.52	0.000
CDD14	47,081	2,255	20.88	0.000
Dec	(2,550,575)	393,428	(6.48)	0.000
MonthDays	1,908,950	113,569	16.81	0.000
Tor_FTEAdjChange	5,020	2,854	1.76	0.081
Statistics based on the rho-differenced data				
Sum squared resid	2.87E+14	S.E. of regression		1,586,270
R-squared	0.9128	Adjusted R-squared		0.9090
F(5, 114)	238.65	P-value(F)		0.0000
rho	(0.2953)	Durbin-Watson		2.58
Statistics based on the original data				
Mean dependent var	7.27E+07	S.D. dependent var		5,253,811

3-Staff-35

Ref. 1: Exhibit 3, p.44

Question(s):

a) Does Burlington Hydro currently track the actual number of customer-owned electric vehicles in its service territory?

b) If not, does Burlington Hydro plan to track this data?

c) Please discuss if Burlington Hydro reviewed either the IESO's Pathways to Decarbonization report (December 15, 2022) and/or the Enbridge Gas Inc. Pathways to Net-Zero Emissions report (revised 25 April 2023) and how these reports were considered in the development of its load forecast, including assumption related to electrification of buildings, vehicles and commercial and industrial activities.

Response:

a) BHI currently does not track the number of customer-owned electric vehicles in its service territory, as this information is not readily available to BHI.

b) BHI does not plan to track ownership data for EVs, however BHI does plan to track the location and types of EV chargers in its service area in order to determine their impact on the distribution system. BHI has obtained data from MTO (Postal Code) and ESA in an effort to research areas of known EVs to learn data and usage patterns and loading trends on BHI assets.

c) BHI has reviewed the IESO's Pathways to Decarbonization report and it was used to develop and test assumptions such as the home heating conversion rate factor for residential customers in developing BHI's load forecast.

3-Staff-36

Reference:
Load Forecast – Additional Loads
Ref 1: Exhibit 3, Additional Loads, pp. 43-50

Question(s):

a) Please discuss how Burlington Hydro developed the 15% home heating conversion rate factor for residential customers.
b) Please provide supporting documentation that informed the development of this factor, including but not limited to recent Burlington Hydro customer conversions, any participant data in broader energy conservation programs (for example, NRCan's Canada Greener Homes) or forecasts developed by the IESO

Response:

a) The 15% home heating conversion rate factor for residential customers was informed by heat pump conversions in Ontario in recent years, and an expectation that electricity heating will increase from the historic period to the test year based on the Burlington Distribution System Sustainability Plan and the IESO's Pathways to Decarbonization report.

b) The home heating conversion rate factor was informed by the trajectory of electricity home heating adoption per the Burlington Distribution System Sustainability Plan[1], the IESO's Pathways to Decarbonization assumption that 100% of new sales of space heating equipment will be electric by 2035, and NRCan National Energy Use Database data which indicates that approximately 10% of the increase in home heating stock from 2020 to 2022 in Ontario has been heat pumps[2].

[1] Burlington Distribution System Sustainability Plan, June 19, 2024, Figure 9

[2] https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&year=2022&rn=21&page=0

3-Staff-37

Reference:
Load Forecast
Ref 1: Exhibit 3, CDM/eDSM Forecast, pp. 55-59

Preamble:

Burlington Hydro states that the 2025-26 CDM forecast is taken from the 2021-2024 provincial share and as savings in 2025 and 2026 were not available at the time of filing, savings were assumed to be the same as 2024.

Question(s):

a) Please update the 2025-26 CDM forecast considering the IESO's new eDSM framework, and in particular the 2025-2027 eDSM plan, which includes a significantly expanded scope and materially higher CDM savings.

b) Provide a table that clearly considers the IESO's new eDSM framework forecast values, Burlington Hydro's share of provincial totals and the forecast CDM impacts over the COS period, including changes to allocations to various rate classes considering the expansion of the IESO eDSM plan.

c) Please discuss if Burlington Hydro intends to propose any Local eDSM programs (also known as Stream 2 programs). If yes, please provide details on when Burlington Hydro expects to file an application and how forecasted CDM impacts are considered in the load forecast.

d) For all changes, please updated Attachment 5 – Load Forecast Model file

Response:

a) Updates to the 2025-26 CDM forecast are provided in responses b) and d).

b) The new eDSM framework values allocated to BHI are summarized in Table 1 below.

Table 1

Program	In year energy savings (GWh)		Allocation to BHI		In year energy savings (kWh)	
	2025	2026	BHI Share	Basis of Allocation	2025	2026
Retrofit	446	519	1.17%	% of provincial kWh	5,234,087	6,090,788
Small Business	14	15	1.17%	% of provincial kWh	164,299	176,034
Energy Management	52	59	1.17%	% of provincial kWh	610,252	692,402
Industrial Energy Efficiency	133	160	1.17%	% of provincial kWh	1,560,838	1,877,699
Home Renovation Savings	61	66	1.17%	% of provincial kWh	715,873	774,551
Local Initiatives	641	693	1.17%	% of provincial kWh	7,522,534	8,132,786
Energy Affordability Program	27	30	1.31%	% of prov. LIM	354,866	394,296
First Nations Program	1	1	0.00%			
Total	**1,375**	**1,543**			**16,162,749**	**18,138,556**

The allocations of eDSM programs to rate classes in 2026 are summarized in Table 2 below. The allocations are based on historic allocations of those programs to rate classes. The Home Renovation Savings program is allocated 100% to the Residential class and the Local Initiatives Program is allocated to rate classes based on total CDM program savings by rate class in the 2015 to 2024 rate period.

Table 2

Program	Allocations			2026		
	Residential	GS< 50	GS > 50	Residential	GS< 50	GS > 50
Retrofit	0%	20%	80%	-	1,062,520	4,171,568
Small Business	0%	88%	12%	-	144,419	19,880
Energy Management	0%	0%	100%	-	-	610,252
Industrial Energy Efficiency	0%	0%	100%	-	-	1,560,838
Home Renovation Savings	100%	0%	0%	715,873	-	-
Local Initiatives	31%	15%	54%	2,369,034	1,098,741	4,054,759
Energy Affordability Program	100%	0%	0%	354,866	-	-
First Nations Program	0%	0%	0%	-	-	-
Total	**21%**	**14%**	**64%**	**3,439,773**	**2,305,679**	**10,417,296**

The allocations of eDSM programs to rate classes in 2027 are summarized in Table 3 below.

Table 3

Program	Allocations			2027		
	Residential	GS< 50	GS > 50	Residential	GS< 50	GS > 50
Retrofit	0%	20%	80%	-	1,236,430	4,854,358
Small Business	0%	88%	12%	-	154,734	21,300
Energy Management	0%	0%	100%	-	-	692,402
Industrial Energy Efficiency	0%	0%	100%	-	-	1,877,699
Home Renovation Savings	100%	0%	0%	774,551	-	-
Local Initiatives	31%	15%	54%	2,561,217	1,187,875	4,383,694
Energy Affordability Program	100%	0%	0%	394,296	-	-
First Nations Program	0%	0%	0%	-	-	-
Total	**21%**	**14%**	**65%**	**3,730,064**	**2,579,039**	**11,829,453**

c) BHI is still assessing whether it intends to propose any Local eDSM programs.

d) BHI provides an updated load forecast model as Attachment_Load_Forecast_Model_BHI_07242025.

4-Staff-38

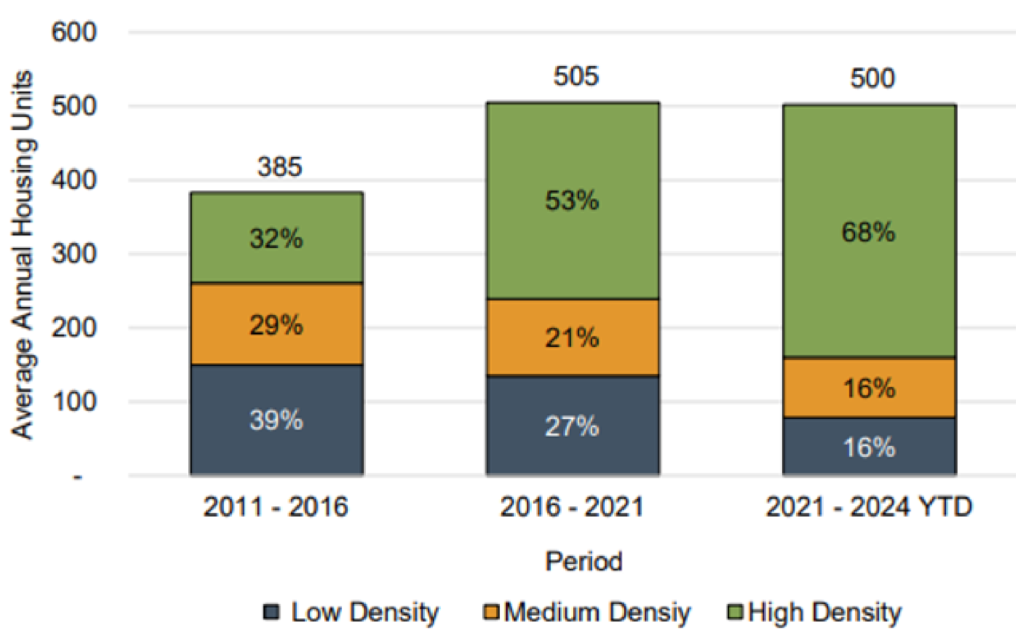
Reference:
City Growth and Housing
Ref. 1: Exhibit 1, Part 1 of 2, Business Overview Part A, p. 13
Ref. 2: Exhibit 1, Part 2 of 2, Appendix I – 2003 Community Report
Ref. 3: Exhibit 2, BHI Business Plan, p.13
Ref. 4: Exhibit 4, 4.1.5.1 City Growth, p. 36
Ref. 5: Exhibit 4, 4.3.1.1 Workforce Planning, Engineering, p. 208
Ref. 6: Growth Analysis Review – City of Burlington, Watson & Associates Economists Final Report February 14, 2025, p. 96

Preamble:

OEB staff notes that Burlington Hydro has made numerous references to both population growth and anticipated construction of 29,000 new housing units by 2031 in the City of Burlington. This assumption is one of the key factors Burlington Hydro identifies as contributing to an expected increase in workload, as well as the justification for the addition of 14 new FTEs in the 2026 Test Year.

In reference 5, Burlington Hydro further states that its forecasted average capital expenditures over the 2026-2030 period are expected to be over 40% higher than the historical average, partly in support of energy transition and growth forecasts.

Figure 6-3
City of Burlington
Five-Year Incremental Housing Growth by Density Type, 2011 to 2024



Question(s):

a) Reference 6 above indicates that between 2021-2024, an average of 500 new housing units were constructed annually, a slight decrease from the 2016-2021 average of 505 annually. Given these trends, please provide an explanation for why Burlington Hydro uses the target of 29,000 new housing units as a key reason for the anticipated increase in workload.

b) Does Burlington Hydro have any additional information which indicates that the City of Burlington will see a substantial increase in the rate of new home construction in the coming years to meet the 2031 target?

c) Does Burlington Hydro believe that this shortfall was due to under resourcing?
Clarification: The ‘shortfall’ refers to the deficit in the construction trend for new housing units versus the 2031 target. ‘Under-resourcing’ refers to what potential factor(s) BHI believes are responsible for the shortfall in the construction trend versus the 2031 target.

Response:

a) Recent public policy changes such as the *More Homes Built Faster Act, 2022* and DSC amendments related to connecting residential projects to the grid are intended to facilitate housing development in Ontario. These policy changes have only recently begun being implemented and are expected to markedly increase the pace of housing growth relative to the historical periods. As such, BHI’s forecast housing growth over the 2026-2030 rate term exceeds the growth experienced during the historical period, referenced in Figure 6-3 above.

Densification is also an important distinguishing factor between the historical and forecasted housing growth. The majority of new housing units in the City of Burlington are multi-residential buildings, most of which will be located in intensification areas in close proximity to the three GO Stations in the City of Burlington. The City has identified these as Major Transit Station Areas (MTSAs), Aldershot GO, Burlington GO and Appleby GO, which are expected to include 7,500 units[1] , 4,000 units[2] and 20,000 units[3] respectively.

BHI notes that there appears to be a discrepancy in the targeted housing units of 29,000 units identified in part a) of the interrogatory above and the 31,500 units identified above

[1] EB-2025-0051, DSP, MISDs, p 30
[2] Ibid, p 37
[3] Ibid, p 44

for the MTSAs alone. The 29,000 units referenced in the Application represents the City of Burlington's 2031 Municipal Housing Target Pledge[4]. Since that pledge was made in March of 2023, BHI forecast the number of units expected to be added as a result of the MTSA developments as 31,500 based on project proposals obtained from Site Plan application data.

b) BHI provided extensive information on the substantial increase in the rate of new home construction in the coming years to meet the 2031 target in its Application. In addition, based on more recent information, the City of Burlington currently has approximately 44,800 housing units in the development approvals process as provided in Figure 6-4 at page 6-6 of its Growth Analysis Review published in February of 2025.[5]

c) BHI cannot comment on the precise reasons for the deficit in the construction trend but notes that legislative and regulatory changes, including the More Homes Built Faster Act, 2022, the Capacity Allocation Model and the extension of the revenue horizon from 25 years to 40 years for residential developments, have recently been implemented by the government and the OEB as "part of a long-term strategy to help build more homes"[6] and "break down barriers that slow the construction of new homes and businesses by making it easier to connect to the province's grid."[7]

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[4] Housing-Pledge-Letter-Package-Sent-to-MMAH-Minister.pdf
[5] Burlington Growth Analysis Review 2024
[6] https://news.ontario.ca/en/backgrounder/1002525/more-homes-built-faster-act-2022
[7] Letter of Direction from the Minister of Energy and Electrification to the Chair of the OEB (December 19, 2024)

4-Staff-39

Reference:
Turnover and Resignations
Ref. 1: Exhibit 4, 4.1.5.2, p. 36
Ref. 2: Exhibit 4, 4.3.1.1 p. 190
Ref. 3: Exhibit 4, Table 45, p. 191
Ref. 4: Exhibit 4, 4.1.2.1 Salaries and Benefits, Table 6, p. 20
Ref. 5: Exhibit 4, 4.3.1.2 Compensation, Table 50, p. 229

Preamble:

Table 45 - Reasons for Resignations

Turnover Reasons	2024	2023	2022	2021	2020	2019
Total Resignations due to Competitor	**5**	**8**	**9**	**6**	**2**	**4**
Retirements	0	2	4	7	2	8
Other Reasons	4	1	3	1	2	2
Total Resignations	**9**	**11**	**16**	**14**	**6**	**14**

Table 50 – Unionized Annual Wage Increase

Year	%
2021	2.25%
2022	2.25%
2023	2.25%
2024	3.75%
2025	3.75%
2026	3.00%

Question(s):

a) Reference 3 indicates that 9 out of 16 resignations in 2022 were due to competitor offers, and 5 out of 9 in 2024, both of which represent approximately 55% of total resignations in their respective years.
   a. Given that higher step increases for salaries were implemented in 2024-2025, has Burlington Hydro seen material impact on annual turnover rates by percentage as a result of increased salaries?

b) Please complete Table 45 in reference 3 above (Reasons for Resignation) for 2025 to date. Please also confirm if the trend outlined above in regard to turnover as a result of increased salary offers by competitors was reduced as a result of Burlington Hydro's 3.75% and 3.0% increases for Unionized employees, respectively.
c) In response to the high employee turnover observed in recent years, what specific strategies—beyond salary increases—has Burlington Hydro implemented to enhance employee retention and remain competitive in the labour market, particularly in terms of career development?
d) What is Burlington Hydro's target turnover rate, and how does it compare to industry benchmarks?
e) Please provide the number of temporary staff hired annually from 2020 to 2024 and the average duration of their employment in FTE.
f) Please provide the number of temporary staff forecasted annually for hire in FTE from 2025 to 2030.

Response a) b) and c):

BHI provides an updated Table 45 for 2025 actuals to June 30 as Table 1 below.

Table 1

Turnover Reasons	2025	2024	2023	2022	2021	2020	2019
Total Resignations due to Competitor	**0**	**5**	**8**	**9**	**6**	**2**	**4**
Retirements	1	0	2	4	7	2	8
Other Reasons	1	4	1	3	1	2	2
Total Resignations	**2**	**9**	**11**	**16**	**14**	**6**	**14**

As shown in Table 1, the total number of resignations due to competitors have decreased in 2024 and 2025 (based on data as of July). The increase in salary is a contributing factor; however, there are many factors that go into managing voluntary turnover, as further discussed below.

In the current labour environment,[1] offering competitive compensation packages remains essential for attracting and retaining talent. In addition, ongoing investment is required in delivering retention programs and strategies and ensuring adequate resource capacity across the portfolio with increased workloads, to create a positive and sustainable work environment.

[1] https://ehrc.ca/labour-market-intelligence/electricity-in-demand-labour-market-insights-2023-2028/

BHI has used the following strategies to enhance employee retention and remain competitive:

a. Talent acquisition and onboarding
b. Upskilling and leadership development
c. Develop a strong employer brand by ensuring a positive work culture and be recognized as a top employer.
d. Providing a safe work environment by enhancing its health, safety and wellness program.
e. Succession planning
f. Performance management and
g. Employee engagement

Understanding shifts in the labour market, offering competitive salaries, and conducting ongoing reviews and adaptations of HR programs are all essential for BHI to attract and retain top talent.

d) BHI has set a 0% target for unwanted turnover—specifically, resignations. This reflects a strong commitment to retaining employees and deploying the strategies listed in a) and c) above. While some turnover is inevitable, especially due to retirements, BHI recognizes that retirements can be managed proactively as employees usually provide advance notice. BHI also has robust succession and workforce planning initiatives to proactively manage retirement-related turnover which gives BHI the opportunity to prepare for transitions.

BHI does not benchmark against the industry for turnover rates.

e) BHI provides the number of temporary staff hired annually from 2020 to 2024 and the average tenure of their employment in months in Table 2 below.

Table 2

Year	# Temps	Average Tenure (Months)
2020	23	5.5
2021	20	6.0
2022	13	7.4
2023	15	6.4
2024	17	6.0

f) In 2025, BHI forecasted 2 temporary FTE. BHI is not forecasting any temporary FTE for hire in 2026 to 2030.

4-Staff-40

Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, p. 183

Ref. 2: Exhibit 4, 4.3.1.1 Workforce Planning, p. 186

Ref. 3: Exhibit 4, 4.3.1.1 Workforce Planning, pp. 193-194

Ref. 4: Exhibit 4, 4.3.1.1 Workforce Planning, Engineering, p. 208

Question(s):

a) Burlington Hydro indicated in reference 2 that residential service requests increased from 317 to 881 from 2021-2024, or 278%. Please confirm increases in residential service requests were accurately indicative of housing and were followed by proportional increase in demand for customer services, connections, and support.
b) Burlington Hydro states that residential connection requests have increased from 317 in 2021 to 881 in 2024.
    i. Please provide the number of residential connection requests in 2022, 2023 and 2025 to date respectively.
    ii. Please provide the number of forecasted residential connections in 2025 and 2026 respectively.
c) Reference 4 states that the Province of Ontario's plan to build 1.5 million homes over the next decade and the City of Burlington's target of 29,000 new housing units by 2031 is expected to further increase the volume of customer service requests, connections, and system upgrades.
    i. Please provide a forecast of the expected growth in the volume of customer service requests, connections, and system upgrades if 29,000 new housing units are built by 2031.
    ii. Please explain the reasoning for why expected growth in the volume of customer service requests, connections, and system upgrades by 2031 contributes in part to the need for 7 additional engineering FTEs in 2026.
    iii. Please provide the overtime hours directly attributable to the engineering team addressing connection requests since 2023. If the figure exceeds a reasonable annual salary for an applicable FTE, please explain why Burlington Hydro has not hired one to decrease costs related to connection requests.
d) Burlington Hydro states that more frequent and severe extreme weather events require system hardening and proactive grid planning. How will the hired candidates assist in this process?
e) Burlington Hydro states an increase in net metering customers from 25 in 2021 to 127 in 2024. Please provide the number of net metering customers in 2022, 2023 and 2025 to date respectively.

Response:

a) BHI confirms that increases in residential service requests are indicative of housing and were followed by proportional increase in demand for customer services, connections, and support.

b)

i. BHI provides the residential service requests for the requested years in Table 1 below.

Table 1

Type of Service	2022	2023	2025 YTD Jun
Residential Connection Requests	851	737	261

ii. BHI provides the forecast for residential service requests in 2025 and 2026 in Table 2 below. These projections are based on historical actuals using a linear regression analysis method and incorporate the impact of the City of Burlington's housing growth goals.

Table 2

Type of Service	2025	2026
Forecasted Residential Connection Requests	1091	1,599

Response to (c) and (d):

BHI has put forward a plan to hire 7 additional Engineering FTEs across a broad range of expertise and skills sets as detailed in the evidence, and further explained in the responses to the following interrogatories: 4-Staff-51, 4-Staff-63, 4-Staff-64, 4-Staff-65 and 4-Intervenors-113g. This plan represents a 41% increase in Engineering FTEs from 2025 to 2026 to support BHI in delivering its 2026-2030 investments plans, commensurate with a forecasted 44% increase in customer service requests from 2025 to 2026; and a 135% increase in customer service requests from 2021-2025 to 2026-2030, as identified in Table 3. Further, the number of requests is not perfectively indicative of the increased workload - requests for larger load connections, including bulk services are more complex and take longer to process.

Table 3 – Forecasted Customer Service Requests, Connections and Upgrades

Description	2026	2027	2028	2029	2030	Total 2026-2030
Forecasted Service Connection Requests	1,669	1,827	1,985	2,143	2,301	9,924

Description	2021	2022	2023	2024	2025	Total 2026-2030
Actual/Forecast Service Connection Requests	374	938	804	945	1,160	4,221

% Increase 2026-2030 as compared to 2021-2025	**135%**
% Increase 2026 vs. 2021	**44%**

In addition to carrying out the incremental engineering workloads associated with serving the forecasted growth and demand in BHI' service territory, these new positions will also play an integral role in the implementation of investments and initiatives to support continuous improvement in system planning, grid hardening and modernization as detailed in Sections 5.2.1.4, 5.3.1, 5.4.1.2.1 - 5.4.1.2.3 and 5.4.2 of the DSP. The hired candidates will assist in this regard by processing, managing and leveraging system data and enhanced analytics to proactively manage system health and asset failure risk, identify and reinforce infrastructure in high-risk areas of the system, and implement automation to improve recovery after outage events.

Below are the specific areas of contribution for each position. BHI must proactively invest in the recruitment and development of these resources in order to advance customer outcomes and policy objectives related to reliability, resilience, DER enablement and cost-effective solutions to enable growth and electrification.

Engineering Supervisors

These leaders are responsible for strategic oversight and technical direction. Their contributions also include cross-department coordination: aligning engineering, operations, and emergency response teams for cohesive planning.

- Supervisor, Energy Transition Integration
    - DER Resilience Integration: Ensuring that distributed energy resources (like solar + storage) are integrated in ways that enhance grid resilience (e.g., capacity and load matching, integration with intelligent switches to enhance DER availability).

- Supervisor GIS (Replacement for redeployment to IT Supervisor)
    - Ensure that GIS system data and records are up to date. Facilitate improvements and integration with groups in Operations (OMS) and Engineering (System Planning) and other groups that rely on GIS data for business purposes.
- Supervisor, Planning & Grid Modernization
    - Scenario Modeling: simulations of extreme weather impacts and planning contingencies.
    - Risk-Based Planning: Identifying vulnerable grid segments/assets and prioritizing upgrades based on climate-related events (e.g. planned replacement of submersible transformers with pad-mount transformers to mitigate the risk of outages from flooding)

Engineering Technicians

These professionals support the design, testing, and implementation of system upgrades and these additional positions are related to increased volumes of work in System Renewal, System Service, System Access investment areas:

- Infrastructure Hardening: Assisting in the design of reinforced poles, undergrounding cables, and upgrading substations with more automation.
- Asset Condition Monitoring: Collecting and analyzing field data to identify aging or vulnerable infrastructure.
- Project Execution: Supporting the rollout of capital projects identified on page 218 in Section 4.3.1.1 of Exhibit 4 and Section 5.2.1.2.1 of the DSP which identifies investments to expand the grid and investments that improve grid durability and flexibility.

GIS Technician

Geographic Information Systems (GIS) technicians provide spatial intelligence that is essential for climate-resilient planning. Currently BHI has only one dedicated resource in this area of expertise with no back-up for emergencies. The GIS Technician is responsible for maintaining records in the GIS and adding new connections. The volume of work is increasing and accurate, up to date information is critical for applications such as OMS and future ADMS operations.

iii. The number of OT hours logged by the Engineering staff member directly involved in customer service requests, since 2023, is identified in Table 4 below.

Table 4

Eng. Position with applicable OT hrs.	2023	2024	2025*
Eng. Service Tech.	370	288	114

*YTD June

e) BHI provides the number of net metered customers in 2022, 2023 and 2025 YTD June in Table 5 below.

Table 5

Type of Customer	2022	2023	2025 YTD Jun
Net Metered Customers	55	83	136

4-Staff-41

Reference:
Load Forecast and Population Growth
Ref. 1: Chapter 2 Appendices, 2-IB Forecast Analysis

Preamble:

OEB staff notes that Burlington Hydro's load forecast shows marginal changes in customers/connections, demand, and consumption 2020-2026.

Question(s):

a) Please reconcile the load growth forecast with the expected growth in population and constriction of 29,000 new residential housing units by 2031.

Response:

a) BHI's load forecast for the 2026 Test Year should not be expected to reflect the expected significant growth in population and construction of 29,000 new residential housing units by 2031 because the growth is not expected to occur before 2028. The population and housing growth is not expected to result in a material change to BHI's load until at least 2028 as connections will not materialize until approximately 2-3 years after consultation with developers, and design and planning of infrastructure occurs. These consultation, design and planning phases will occur in 2025 and beyond, resulting in a change in customer connections in 2028 and beyond. As such, the connections resulting from the expected growth in population and construction of 29,000 new residential housing units by 2031 are not reflected in the 2026 load forecast. Please refer to 4-Staff-38 a) for further details.

4-Staff-42

Reference:
Locate Requests
Ref. 1: 4.3.0.7 Distribution Maintenance and Operations, Table 26, p. 102
Ref. 2: New FTE, Operations Clerk, p. 220

Preamble:

Table 26 - Cost per Locate

Description	2021	2022	2023	2024	2025 Bridge Year	2026 Test Year
# of locates	12,905	14,603	14,203	15,775	15,931	16,498
$ Cost of locates	$389,799	$409,406	$408,675	$464,437	$505,923	$520,695
$/locate	$30	$28	$29	$29	$32	$32

Burlington Hydro indicates that one of the primary responsibilities of the new proposed Operations Clerk FTE is facilitating locate requests to accurately identify underground infrastructure, supporting safe and efficient operations for contractors and crews. The number of locates requests, as shown in reference 1, is expected to increase from 12,905 in 2021 to 16,498 in 2026.

Question(s):

a) Please provide the overtime hours for the Engineering Clerk from 2021 to 2024.
b) Please provide the Service connection requests from 2021 to 2024 and forecasted for 2025 to 2030.
c) In addition to the Engineering Clerk, are there any other staff members currently supporting the processing of service requests? If yes, please confirm how many employees were involved in assisting with these requests each year from 2021 to 2024, and provide the forecasted number of supporting staff for the period 2025 to 2030.
d) Please confirm whether locate request volumes directly result in increased workload in a linear fashion, or if workload synergies and efficiencies can be achieved despite higher volumes.
e) Please provide overtime hours associated with completing locate request volume 2021-2025.
f) Given that locate requests were previously the responsibility of an Engineering Clerk, please explain why a 13% increase in locate requests from 2022-2026 justifies the creation of a new FTE role whose primary responsibility would be to facilitate locate requests.

g) Given that locate requests are presented as a time-intensive responsibility which necessitates the creation of a new FTE role, what new responsibilities have been allocated to the Engineering Clerk which had been previously been responsible for location requests.

h) Burlington Hydro states in reference 2 that it expects the number of locate requests to increase as a result of anticipated housing growth in the City of Burlington. Please provide a forecast increase in locate requests as a result of this assumption for 2026-2030.

i) Burlington Hydro outlines several risks if the position is not funded (e.g., delays in processing service requests, challenges with metering compliance, AMI upgrade limitations, locate-related safety incidents, or penalties from Ontario One Call). Has Burlington Hydro experienced any of these issues to date? If so, please provide examples.

j) Burlington Hydro states that without proper funding, digs by excavators without proper information about the location of the underground infrastructure, could potentially result in damages to distribution assets, system outages and major safety risks to field workers or the public. Has Burlington Hydro experienced any incidents which stemmed from poor locate information in the historical period?

Response (a)-(g):

Current State: There are currently two clerk positions in the Engineering Department:

- **Engineering Clerk:** supports day-to-day operational requirements including responding to customer inquiries related to service connections and upgrades, scheduling service appointments with customers, processing internal engineering documents, coordinating permits, and responding to third-party (i.e. Electrical Safety Authority) inquiries. The Engineering Clerk also assists with facilitating continuous improvement in engineering processes, such as optimizing engineering workflows to support the evaluation of requests to connect Distributed Energy Resources (DERs). The Engineering Clerk is the only staff member currently processing the intake of service connection and upgrade requests. Table 1 below shows the Overtime Hours of the Engineering Clerk from 2021-2024.

Table 1 – Engineering Clerk Overtime Hours

	2021	2022	2023	2024
Overtime Hours	18.5	8.5	-	-

Locate Clerk: processes and manages requests related to service locates to ensure safety and compliance with regulatory requirements. These duties are becoming more demanding because of the increased volumes of work (as shown in Table 3 below) and because of the incremental requirements resulting from the *Getting Ontario Connected Act*. Locate requests have increased in number and complexity. LDCs must respond to standard locates within 5 business days and complex/multi-address locates within 10 business days or risk administrative monetary penalties. This requires the Locate Clerk to implement rigorous internal tracking and record keeping, and continuously monitor locate status to ensure compliance.

The Locate Clerk has not incurred any overtime during the historical period.

Future State: To support the increased volumes of work associated with locates (which drive increased workload in a linear fashion) and other operational requirements, BHI plans to hire an Operations Clerk FTE and move the Locate Clerk's duties from Engineering to Operations to streamline this role within operations. The benefits /advantages of this role being in operations rather than Engineering are as follows:

- Alignment with operational workflows
  - Aligns the administrative function with day-to-day service delivery, facilitating more direct oversight and responsiveness
  - Operations teams are typically structured to manage real-time service demands and customer requests, making them better suited to the dynamic and time-sensitive nature of locates work
- Streamlined coordination and communication – the operations department manage all project scheduling, dispatch, field crew management, and direct customer interactions. Placing this role in operations allows for:
  - Faster resolution of field issues
  - Real-time updates about locate status
  - Improved scheduling and prioritization
  - Reduced risk of miscommunication or delays resulting from departmental silos
- Enhanced availability and responsiveness - recent regulatory changes, such as the Dedicated Locator model and tighter enforcement from bodies like Ontario One Call,

have placed greater accountability and administrative workload on BHI. Adherence to legislated deadlines (e.g., the five-business-day delivery window), rigorous record-keeping, quality control, and rapid response to audits are critical. Placing this role in the operations department will facilitate timely responses to field changes, and customer and contractor change requests.

In addition to locates, the new Operations Clerk will assist the Metering program with processing metering service requests, appointment scheduling and completing the administrative tasks associated with the implementation of AMI 2.0 as mentioned in Section 4.3.1.1 of Exhibit 4 on pages 220 to 221. This change will allow the Engineering function to be supported by two FTEs going forward: the existing Engineering Clerk and another hire. Together, these two FTEs will be able to handle the anticipated increase in the number of customer requests for new and upgraded services to facilitate timely responses to customers and enable growth and electrification in BHI's service territory (as shown in Tables 2 and 3 below) without compromising the other important work requirements in this portfolio as noted above (i.e. permits co-ordination, responding to ESA inquires). They will also be able to improve customer experience and response timeliness, enhance timely and effective coordination with permitting agencies and third-parties (such as the ESA, Ontario One Call, the City of Burlington, Halton Region, Trans-Northern Pipeline, communication companies, contractors, electricians and the general public), and support continuous process improvements and initiatives in the Engineering program. This will support faster processing of customer service requests and applications, municipal consents, demolition permits, easements, EV charging infrastructure applications, site plan, zoning and committee of adjustment processing, attachment permits, instruction orders and connection orders.

Table 2 – Historical and Forecasted Volume of Connection Requests

Description	2021	2022	2023	2024
Total Service Connection Requests	374	938	804	945

Description	2025	2026	2027	2028	2029	2030
Forecasted total Service Connection Requests	1,160	1,669	1,827	1,985	2,143	2,301

Table 3 – Updated Locate Volumes and Costs (as filed in 4-Intervenor-105d).

Description	2021	2022	2023	2024	2025 Bridge Year	2026 Test Year
# of locates	12,905	14,603	14,203	15,775	17,354	17,861
Total cost of locates	$ 389,799	$ 409,406	$ 408,675	$ 464,437	$ 551,119	$ 567,210
$ per locate	$ 30.21	$ 28.04	$ 28.77	$ 29.44	$ 31.76	$ 31.76

h) BHI has not forecasted the number of Locates beyond the 2026 Test Year, but expects that the volumes of locates will increase over the next rate term based on the forecasted growth in service requests/connections/upgrades as identified in Table 3 in BHI's response to 4-Staff-40.

i) Yes, due to increased demands on these roles, BHI is seeing increased risk of delays and compliance challenges associated with the completion of the above-noted tasks, necessitating more rigorous oversight and involvement of management in the day-to-day activities of the portfolio.

j) Dig-ins can be caused by various factors including contractor error, inadequate communication, or poor quality records. BHI has not experienced any dig-ins historically due to poor locate information, but this is a high-priority risk that BHI must continue to actively manage as locates volumes increase. The proposed Operations Clerk will manage this risk by maintaining and where possible improving coordination and communications with the contractor and assisting with timely resolution of locate issues identified by contractors.

4-Staff-43

Reference:
Increased Workload
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Key Business Drivers Affecting Workforce Planning, p. 185

Preamble:

Burlington Hydro cites increased workload as one of the key trends and factors of its Workforce Planning.

Question(s):

a) Burlington Hydro cites that total employment in the Canadian electricity sector has increased by over 12% in the past five years, equivalent to an average annual growth rate of 2.3%.

   i. Please provide an explanation for why Burlington Hydro's proposed 2026 FTE count of 123 versus 100 in the 2021 OEB-approved is nearly double that figure at 4.23% (CAGR).

   ii. Please confirm whether Burlington Hydro's workload per FTE is representative of the Canadian electricity sector or if the average workload per FTE is exceptionally high. If the latter, please provide an explanation.

b) Burlington Hydro states that Locate volumes, which are directly proportional to non-discretionary System Access projects such as residential and commercial developments and renovations, and road widening projects, are expected to increase by 28% from 2021 to 2026. Does Burlington Hydro expect that figure to continue to increase? If so, please provide a forecast of expected Locate Volumes to 2030.

Response:

a) i) The premise of the first part of this question is flawed because the historical timeframe (2017-2022) cited in the Electricity in Demand: Labour Market Insights 2023-2028[1] ("the Report") is not comparable to the timeframe (2021-2026) that is relevant to this Application.

[1] https://ehrc.ca/wp-content/uploads/2024/05/Electricity-in-Demand-Labour-Market-Insights.pdf

Using a more comparable and relevant timeframe, BHI notes that employment in the electricity sector is expected to grow by 12,000 jobs from 2022-2028 according to the Report.[2] From 2021 to 2026 specifically, employment in the electricity sector is estimated to grow at an average of 3.5% from per year,[3] which is greater than BHI's FTE growth over the same period of 2.4% from the 2021 actuals to the 2026 Test Year (112 FTE to 123 FTE).[4]

ii) BHI is unable to answer the second part of the question because it does not have information about the average workload per FTE of the Canadian electricity sector.

b) Please refer to BHI's response to 4-Staff-42 h).

[2] Ibid, p95,
[3] Ibid, p90, Table 6 and Figure 42
[4] Please see BHI's response 4-Intevenor-99 for an explanation of the FTE variance between 2021 Test Year approved by the OEB in the last cost of service application and the 2021 actuals.

4-Staff-44

Reference:
Corporate Services Advisor
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Corporate Services Advisor, p. 197

Question(s):

a) Please identify the critical operational and regulatory needs addressed by the Corporate Services Advisor and how this role will address these needs.

b) The growth in customer communications grew from 430 to 566 (30%) 2020-2024. Please provide updated figures for 2025 and 2026 (to date).

c) Please explain how the growth in social media following across the four social media platforms identified directly translate to an increased workload for the Communications Advisor.

d) When does Burlington Hydro expect to implement proactive initiatives such as SMS texting of Outage notes to customers?

Response:

a) The Corporate Services Advisor supports Board of Director, Senior Team and governance coordination. In addition, this position ensures compliance with Ontarians with Disabilities Act (AODA) and privacy regulations. This role is integral in managing a variety of core administrative and compliance-related functions that are foundational to the organization's governance. The Advisor coordinates documentation and preparations for Board and Senior Team meetings, oversees the tracking and implementation of board directives, and serves as a point of contact for inquiries related to governance matters. Additionally, the Advisor works to ensure that all corporate policies and practices align with the AODA, privacy legislation (MFIPPA) and OEB Ontario Cyber Security Framework (OCSF) required privacy elements, conducting regular reviews and updates as necessary to maintain compliance.

b) Customer communications requirements increased due to an increase in customer outages from 430 in 2020 to 566 in 2024 (30%). 2025 customer outages on a May YTD basis were 313. Actual outages are not yet available for the remainder of 2025 or 2026.

c) As the social media following across the four identified platforms has grown, the Communications Advisor faces a corresponding increase in workload for several reasons.

- A larger audience leads to a higher volume of content that must be created, curated, and scheduled to maintain consistent engagement. Every post, update, or announcement needs to be tailored to fit the unique style and preferences of each platform, requiring both creativity and strategic planning.

- Increased followership brings a surge in public interactions, including direct messages, comments, and inquiries. The Communications Advisor must monitor, moderate, and respond to these interactions in a timely and appropriate manner, ensuring accurate information is shared and brand reputation is maintained.

- With a broader and more diverse audience, there is a greater need for analytics and reporting. The Communications Advisor must analyze engagement metrics, track trends, and adapt strategies to maximize impact, all of which involve additional research and reporting.

In summary, the growth in social media following significantly increases the scope and complexity of the Communications Advisor’s responsibilities, translating directly into a greater overall workload.

d) BHI is currently in the development stage and expects to fully implement SMS texting of outages to customers by the end of 2025.

4-Staff-45

Reference:
Financial Analyst
Ref. 1: Exhibit 4, 4.3.1 Workforce Planning, Financial Analyst, p. 206

Question(s):

a) Please confirm who currently performs the financial planning, regulatory compliance, and capital tracking functions that the proposed Financial Analyst would assume.

  i. Please provide the overtime hours completed for this existing role from 2021 to 2024.

b) What specific gaps or delays have been observed in these areas that justify the need for an additional full-time resource?

c) Burlington Hydro states that with accident claims rising from 16 in 2021 to 36 in 2024. Please provide the number of third-party damage claims processed each year from 2021 to 2024, and the average time to resolution.

  Clarification: The IR referring to claims, and there was a typo in the date range. The IR should read "Burlington Hydro states that accident claims have increased from 16 in 2021 to 36 in 2024. Please provide the amount of accident claims from 2021-2025 to date respectively, and the average time to resolution.

d) What is the estimated financial impact of delayed or unprocessed claims on Burlington Hydro's capital or OM&A budgets?

e) Burlington Hydro outlines several risks if the position is not funded (e.g., missed filings, financial misstatements, delays in reporting). Has Burlington Hydro experienced any of these issues to date? If so, please provide examples.

Response:

a) Financial planning, regulatory compliance and capital tracking related responsibilities are currently dispersed among various roles in the Finance department (Controller, the Financial Accountant and Analyst, or the Accountant, Financial and Regulatory), including a temporary Co-Op student. BHI does not track overtime hours for these positions.

  Since 2021, the Co-Op student has contributed between 650 and 1,300 hours per year supporting the Finance department. However, going forward, the Co-Op student is not included in the 2026 Test Year budget because the proposed Financial Analyst will eliminate this role. Replacing the Co-Op student with a permanent role is preferred because it (i) provides stability and continuity, particularly for audits and reporting, (ii) enables the employee to gain familiarity with BHI's financial systems, processes and reporting standards, (iii) reduces time spent onboarding and training, and (iv) allows for more flexibility to assign tasks and manage workflow for sensitive financial data.

b) BHI has been managing an increasing number of operational risks and challenges in this portfolio that justify the need for an additional full-time resource, in addition to the risks identified in Exhibit 4, p. 208 at lines 4-17:

- **Processing Accident-Related Invoices**: The current process for preparing and issuing accident-related invoices is cumbersome and requires ongoing follow-up to gather necessary documentation and approvals such as accident reports, work order information and police reports. Given the time-sensitive nature of submitting insurance claims, these delays can result in the inability to recover costs.

- **Budget Reconciliation and Financial Reporting:** Completing monthly budget to actual reconciliation and financial reporting is a manual process that involving the extraction of data, cross-referencing with source documents, and analyzing variances.

- **Miscellaneous Invoice Recoveries**: Recovery of accounts payable related to non-trade invoices necessitates persistent follow-up efforts. BHI does not have a dedicated resource for non-trade collections and as such it has been difficult to consistently follow-up on outstanding balances, leading to delays in collection which can negatively impact cash flow, and increase bad debt expense.

- **System Limitations and Capital Budgeting Constraints**: The existing IXP system lacks the functionality to support the detailed calculation and analysis of depreciation expense variances. Identifying and explaining variances in depreciation is time-intensive that typically requires the assistance of a temporary or Co-op student. The addition of a dedicated resource would eliminate this requirement and allow for more consistent and efficient analysis.

- **Developer Buy-Backs and Deposit Refunds**: The processing of developer buy-backs, including the calculation and refund of balance and expansion deposits, is resource-intensive and prone to delays. There are gaps in the current workflow that need to be addressed to ensure accurate and timely processing.

- **Insurance Claim Processing**: Insurance claims submitted by BHI customers due to power outages require status updates to customers which, due to resourcing constraints, BHI is unable to provide in a timely manner. This consequently negatively impacts customer satisfaction.

c) BHI provides the accident claims in Table 1 below. The average time to resolve a damage claim is from 16-18 months.

Table 1

Description	2021	2022	2023	2024	2025 June YTD
Accidents	16	11	17	36	34

d) BHI estimated that the financial impact of delayed or unprocessed claims on Burlington Hydro's capital or OM&A budgets is $0 per year in 2026, as the budget is predicated on BHI having adequate resources to process claims on a timely basis.

e) To date, BHI has not encountered any of the issues noted in part e) (missed filings, financial misstatements, or reporting delays). BHI has managed these risks primarily by placing increased demands and strain on current resources within the department. This approach is not sustainable in the long term, as it may lead to employee burnout and/or increased turnover, which could compromise the accuracy, quality and timeliness of this work. Additionally, workforce investment is needed in this portfolio to meet the future challenges outlined in Exhibit 4 (pages 206-208) and referenced in BHI's response to 4-Staff-62.

4-Staff-46

Reference:
Human Resources
Ref. 1: Exhibit 4, 4.3.1 Workforce Planning, HR Analyst/Generalist, p. 221-222

Question(s):

a) Please confirm the current size and structure of Burlington Hydro's HR team, including roles and responsibilities.

b) Burlington Hydro states that that without the new HR Generalist/Analyst role, it may struggle to hire and retain the necessary talent to meet operational needs, potentially impacting service delivery and customer satisfaction. Has Burlington Hydro experienced any delays or service issues related to recruitment, onboarding, or compliance due to current HR capacity?

c) How many recruitment cycles or job postings does the HR team manage annually, and how is this expected to change from 2025 to 2030?

Response:

a) The HR team currently includes 4 employees:
   - Director, People & Culture
   - HR Business Partner, Total Rewards & People Services
   - HR Business Partner
   - Coordinator, People & Culture

   Role Descriptions:

   Director, People & Culture

   The Director is responsible for shaping and executing progressive Human Resources (HR) and People strategies aligned with the organization's current and future needs. This role provides strategic direction and operational oversight for the full scope of HR functions, ensuring alignment with corporate goals, regulatory requirements, and industry best practices. In addition, this position leads the design and implementation of initiatives that enhance organizational effectiveness, talent acquisition and retention, workforce and succession planning, employee engagement, and performance management. The Director champions a people-first culture by supporting inclusive, responsive, and forward-thinking HR policies and programs. The Director also provides expert guidance to people leaders and ensures compliance with employment legislation, corporate policies, and collective agreements. The Director plays a central role in managing employee and labour relations, advising on complex issues, and supporting sound decision-making in workforce planning and budgeting processes.

HR Business Partner, Total Rewards & People (Labour) Services:

The HRBP is a key contributor to the successful delivery of People & Culture services, with a focus on three core areas: Payroll & Benefits Administration, HR Costing and Analysis, and Labour Relations. This role supports continuous improvement by collecting, analyzing, and reporting on key HR trends and support for collective agreement negotiations, Cost of Service, and annual HR financial budgeting and reporting. In addition, the HRBP is responsible for overseeing managing the effective administration of the organization's payroll system and benefits programs. This includes providing support to the HR Business Partner, Talent & Culture to ensure timely, accurate payroll processing, pension administration, and related reporting and analysis. The HRBP acts as a payroll backup when this position is absent. Additionally, the HRBP supports labour relations efforts, ensuring alignment with collective agreements and legislative requirements.

HR Business Partner (HRBP), Recruitment, Talent & Culture and Payroll Administration:

The HRBP contributes to the execution of human capital strategies across all areas of Talent Management. This role is responsible for administering the day-to-day operations of the HR function including the weekly payroll processing, pension and benefits programs, and providing support of the Performance Management System, ensuring consistent application of programs and providing guidance to leaders throughout the organization. The HRBP manages the end-to-end recruitment activities, partnering with managers to attract top talent, and ensure compliance with processes and legislation. In addition, the HRBP leads employee onboarding, new hire orientation, and the delivery of employee engagement initiatives. This position is instrumental in building people capabilities, supporting a culture of continuous improvement, and fostering employee engagement across the organization.

Coordinator, People & Culture

The Coordinator provides administrative support to the Human Resources team members. The Coordinator, People and Culture is responsible for administrative tasks and helping employees with minor inquires such as, but not limited to, managing incoming job applications; scheduling interviews; posting jobs; coordination and setting up for meetings; and maintaining employment records by entering employee data into the HRIS and H&S systems and employee files. The incumbent supports HR processes by administering tests, scheduling appointments, organizing and participating in employee onboarding, and maintaining records and information.

b) The current structure of the HR team has capacity gaps that limit the department's ability to provide timely, strategic, and high-quality HR services both within the company and to external stakeholders, such as potential candidates. For instance, the weekly payroll administration, which involves reviewing, auditing, and approving entries, is time-consuming and requires dedicated attention. Despite efforts to re-engineer the workflow to distribute payroll responsibilities between the two HR Business Partners, the ongoing operational workload still restricts the team's capacity to focus on other priorities.

The introduction of new employment legislation, which requires employers to meet response time obligations, maintain records retention, and comply with job posting regulations, has further increased the HR team's operational workload. Meanwhile, the Director is primarily focused on managing day-to-day operations, leaving limited capacity to concentrate on long-term planning, program development, and proactively aligning people strategies with business goals.

The introduction of the HR Analyst/Generalist role will allow for more consistent and dedicated attention to program delivery, improved coordination across HR functions, and enhanced service. Major changes include greater efficiency in rolling out initiatives, the ability to offer more proactive HR solutions, and relieving current staff from being overstretched and overworked, thereby allowing them to focus on their core responsibilities.

Please refer to 4-Staff-66 a) for further details on this new role.

c) The HR team oversees the full-cycle recruitment process for all positions, including permanent, temporary, and student hires. On average, the team manages approximately 32 positions each year.

Over the next five years, recruitment activity is expected to increase due to numerous factors, including:

- Employee turnover is anticipated to rise as a result of competitive labour markets and industry shortages in key occupations such as managers, engineers, technicians, technologists, trades, and ICT professionals according to the EHRC labour market study ("EHRC Study").[1]
- The EHRC Study also predicts that the electrical industry will require a labour force increase of approximately 25% due to energy sector growth.
- BHI's has experienced double-digit turnover rates averaging 11.3%

[1] Electricity in Demand: Labour Market Insights 2023-2028

Effectively managing turnover at BHI requires ongoing investment in both retention and attraction strategies. Unplanned departures disrupt operations, increase costs, and result in lost institutional knowledge while new hires are onboarded. As mentioned above, according to recent EHRC market survey projections, BHI anticipates that turnover levels will remain elevated in the foreseeable future. In this competitive environment, while offering competitive compensation packages remains essential for attracting and retaining talent, it is not sufficient on its own. The labour market continues to evolve rapidly, so it is critical for HR programs to be consistently reviewed and adapted to align with both changing employee needs and shifting market conditions. These HR programs typically encompass areas such as talent acquisition, onboarding, employee training and development, health, safety and wellness, succession planning, performance management, and employee engagement initiatives.

Ongoing review and proactive HR adjustments are essential for BHI to stay competitive, supportive, and retain top talent.

4-Staff-47

Reference:
Billing Representative
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Billing Representative, p. 199
Ref. 2: Exhibit 1, 1.6.4.1 Billing O&M, p. 94

Preamble:

Table 23 - Billing O&M Cost ($) per Customer vs. Industry Average

Billing O&M Cost ($) per Customer	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$11.80	$13.57	$17.04	$19.03	$18.00	**$15.89**
YoY Change		15 %	26 %	12 %	(5)%	
Industry						$36.41
vs. Industry Average						**(56)%**

Table 24 - Billing O&M Cost ($) per Customer YoY Change

Billing O&M Cost ($) per Customer	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$17.23	$21.57	$22.58
YoY Change	(4)%	25 %	5 %
vs. 5-year Average	8 %	36 %	42 %

Question(s):

a) Tables 23 and 24 in reference 2 above indicate that Billing O&M costs per customer have decreased to $17.23 per customer in 2024 actuals, down from a high of $19.03 per customer in 2022. As most of the increased workload outlined in reference 1 above increased during the period leading up to 2024, the decreasing billing O&M costs per customer suggest that the increased workload volume has not translated into increased costs.

   i. Please provide an explanation for why Burlington Hydro saw a decrease Billing O&M costs during the period 2021-2024 while experiencing higher workload volumes.

   ii. Please confirm that the 25% and 5% in Billing O&M costs per customer in 2025 and 2026, respectively, were not as a result of increased workload volumes but instead increased Canada Post costs.

b) In reference 1, Burlington Hydro states that the Meter Inside Settlement Timeframe ("MIST") Meter project, implemented in June 2022, which required all GS>50kW customers to be billed on the Hourly Ontario Energy Price, required Burlington Hydro to implement a new billing process which requires additional resources to manage. Please provide additional details on the resources required to manage this project since 2022, and which FTE(s) added since 2021 have been allocated these tasks to date.

Response:

a) The decrease in Billing O&M costs from $19.03 per customer in 2022 to $17.23 per customer in 2024 is primarily attributable to a decrease in postage, mail service and printing costs. These cost reductions are not related to work volumes that drive labour related costs in Billing O&M. To demonstrate this, in Table 1 below, BHI restated the information in Tables 23 and 24 to exclude postage, mail service and printing costs. The remaining costs are primarily labour related Billing O&M costs inclusive of salaries, benefits and temporary staff. The normalized analysis in Table 1 shows that the labour-related Billing O&M costs have gone up as a result of the increased workload volumes.

Table 1 – Labour-Related Billing O&M Cost per Customer

Description	2019	2020	2021	2022	2023	2024	2025	2026
$ excl Postage/Mail Service/Printing	$424,419	$563,255	$638,383	$675,580	$717,692	$655,822	$841,277	$911,939
# customers	68,205	68,568	68,742	68,879	69,171	69,266	69,592	69,919
$ excl Postage/MailService/ Printing/customer	$6.22	$8.21	$9.29	$9.81	$10.38	$9.47	$12.09	$13.04
% change		32.0%	13.1%	5.6%	5.8%	-8.7%	27.7%	7.9%

While the increased Canada Post costs are certainly a large driver of the increase in Billing O&M per customer in 2025 and 2026, Table 1 above shows that labour requirements related to increased work volumes (as detailed at Exhibit 4, pp. 199-200) are proportionally driving the increase in Billing O&M per customer.

b) The MIST meter project was one of many changes that justified the need for two additional resources, as identified on page 61 of Exhibit 4. All billing representatives are responsible for managing the new billing process for MIST meters i.e. tasks are allocated amongst all billing staff, which is no different from billing for all other types of accounts/meters.

The new tasks associated with the MIST meter billing project are related to pricing, settlement and unbilled revenue calculations. Prior to the MIST meter conversion project, BHI's third party contractor was able to read and transmit meter data for all interval meters. This data is used by the third party to calculate BHI's Net System Load Shape ("NSLS") which is required for settlement and unbilled revenue calculations. This process did not involve BHI and was automated.

With the conversion of meters to MIST meters, MIST meter data is also required for the calculation of BHI's NSLS. BHI's third party is unable to read and transmit meter data for MIST meters because they are only able to read meters which have a phone line or modem. As such, BHI is responsible for reading and transmitting this data to its third party. The billing team requires additional resources for (i) new tasks such as communicating MIST meter information to the third party (e.g. status, installations, upgrades, removals and replacements) to ensure that BHI's NSLS is accurate; and (ii) increased workload as the billing process (first and final bills; and billing accuracy) has become more complex.

4-Staff-48

Reference:
Hiring Processes
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Two Additional Powerline Apprentice Staff, p. 201

Question(s):

a) The OEB recognizes that proactive hiring processes to ensure staff competency are an important element of Workforce planning.

i. Please explain why it would not be feasible for Burlington Hydro to consider hiring Journeypersons with an existing minimum of 5 years experiences as the need arises. If this is due to salary considerations, please explain why it is more cost efficient to train an employee for a minimum of 5 years before promoting them to a higher salary versus offering an experienced Journeyperson a higher salary and eliminating the need for 5 years of training.

ii. Has Burlington Hydro encountered any previous difficulties in hiring experienced Journeypersons in the past?

iii. Please confirm how many senior journeypersons are currently employed.

iv. Please confirm how many metering technicians are currently employed.

Response:

a)

i. Labour market trends are continuously monitored and staffing decisions continually assessed as part of the company's ongoing workforce planning efforts to ensure operational needs are met in a cost-effective manner.

At this time, there are several reasons why hiring Journeypersons with a minimum of 5 years' experience as vacancies arise is not a preferred alternative to hiring apprentices. First, BHI faces an increasingly competitive labour market, making experienced Journeypersons in specialized trades unique to its industry, particularly difficult to recruit. The pool of qualified external candidates is often limited, and those who are available may already have established positions elsewhere or be in high demand, resulting in potentially lengthy vacancies or unsuccessful hiring campaigns.

Salary is not necessarily the main factor in attracting candidates. Although a higher salary may appeal to some experienced candidates, BHI's ability to attract qualified individuals is influenced by collective agreement provisions, including seniority-related entitlements such as vacation. In addition, the overall cost efficiency is not guaranteed as externally hired Journeypersons may require time to adapt to BHI's specific operational protocols, safety standards, and company culture. By contrast, training employees internally provides Burlington Hydro with greater control over workforce development. It ensures that staff are familiar with the company's equipment, procedures, and expectations from the outset. This proactive approach allows for succession planning, reduces the risk of skill gaps due to unforeseen retirements or departures, and fosters employee loyalty and retention.

ii. BHI has experienced challenges in recruiting qualified Journeypersons, due to a highly competitive labour market and a limited pool of experienced candidates.

For example, in 2024, BHI posted an opening for a Journeyperson Metering Technician. Despite launching an extensive search and advertising the position across multiple industry recruitment channels, the first round yielded zero qualified Journeyperson applicants—only individuals lacking the specialized certification or with insufficient experience applied. After reposting the role and trying outreach efforts again, only a single applicant emerged who met all the required qualifications.

This situation is not unique. Many experienced Journeypersons, particularly those with significant seniority or approaching retirement, are reluctant to leave established positions elsewhere—often due to collective agreement restrictions, seniority-related benefits, and the uncertainty of transitioning into a new workplace. In several instances, promising external candidates have withdrawn midway through the process after learning that benefits such as vacation entitlements could not be matched.

iii. BHI has 25 journeypersons across all trades.

iv. BHI has 4 metering technicians. 3 are journeypersons and 1 is an apprentice.

4-Staff-49

Reference:
Power Line Apprentice
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Powerline Apprentice, pp. 201-202
Ref. 2:

Question(s):

a) Please provide reasoning for why one additional Powerline Apprentice was hired in 2021, in addition to the approved FTE number approved in Burlington Hydro's 2021 Cost of Service proceeding.

b) Please provide amounts for Powerline Apprentice overtime hours from 2021-2025.

Response:

a) The labour market was competitive and hiring during the pandemic was difficult. Therefore, BHI decided to fill this role early in anticipation of a future retirement and possible churn of existing staff. BHI hired a current Powerline Technician Co-op incumbent as an Apprentice after completing two terms with BHI, having already invested training resources to ensure readiness for the apprenticeship.

b) BHI provides amounts for Powerline Apprentice overtime hours from 2021-2025 in Table 1 below.

Table 1

Position Title	2021	2022	2023	2024	2025	Total
Powerline Apprentice	2,104	1,903	1,205	1,073	799	7,084

4-Staff-50

Reference:
Engineering Director
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Director of Engineering, p. 202

Question(s):

a) Please specify how long the position of Director of Engineering was vacant for. In addition, please provide the year in which this role was filled.
b) Burlington Hydro states that the duties assigned to this role were previously shared across multiple other management roles. Please provide a summary of these specific duties which had been previously allocated to other roles.
c) Burlington hydro states that in addition to day-to-day operations, this position has oversight of new capital projects associated with infrastructure needs and the maintenance of the distribution system are designed in accordance with stringent safety and design standards, ensuring long-term plans and expenditures are appropriate.
    i. Please provide a list of the new capital projects associated with infrastructure needs and the maintenance system which this position will have oversight over.

Response:

a) The position of Director of Engineering was vacant from July 2019 and was filled externally in August 2021.

b) The Director of Engineering reports to the Vice-President, Engineering Services and Network Operations. This role provides leadership and oversight to the Engineering team, guiding the full range of services within the engineering portfolio, which includes distribution system protection and control schemes, short and long-term system planning, capital projects, and customer connections.

   During the vacancy noted in part (a) of this response, BHI redistributed key responsibilities among the current team (i.e. three manager-level Distribution Engineers and the Vice-President, Engineering Services & Network Operations). The specific responsibilities taken on by the other staff during the vacancy included:

   - Customer connections – overseeing the successful service delivery of customer connections, managing contractors, and ensuring compliance with safety protocols and procedures.

- System planning – managing the distribution system protection and control schemes.

- Asset management – ensuring that capital projects related to infrastructure and distribution system maintenance design adhere to safety and design standards.

- Large capital projects – directing both existing and new projects, ensuring design standards and proper management of resources and expenditures.

- Management and oversight of department and capital project budgets

- Oversight of the distribution system protection and control schemes – ensuring effective management and functionality in this area.

- Team mentoring, performance management and leadership of the division was provided by Vice-President's of Engineering and Operations.

Temporary reassignment of responsibilities ensured continued service and project management during the Director of Engineering vacancy, but this approach was not sustainable for the long-term. A permanent Director is necessary for effective leadership and oversight of the Engineering division. The role has now been filled, with a renewed emphasis on developing BHI's team and addressing evolving customer, regulatory, and industry needs to support growth, electrification and modernization.

c) The capital projects that are directly managed by the Engineering Department and consequently fall under the responsibility of the Director of Engineering for planning, design, coordination, and execution (in cooperation with departments such as Operations and Finance) are categorized in the DSP investment areas of System Access, System Renewal, and System Service. Please refer to the following evidence in the DSP:

- For a list of System Access projects, please see Table 5.4-9 at page 120.
- For a list of System Renewal projects, please see Table 5.4-10 at page 134.
- For a list of System Service projects, please see Table 5.4-12 at page 142.

This position is also responsible for overseeing asset inspections, condition assessments, and cable and pole testing programs which form part of the OM&A investment plan.

4-Staff-51
Engineering Services Technician
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Engineering Services Technician, p. 203
Ref. 2: Distribution System Plan, Table 5.4-9

Preamble:

In reference 1, Burlington Hydro states that there was an increase in service upgrades and connections which are captured in the General Service programs identified in Table 5.4-9 of the DSP, and that General Service projects have increased by 54% from $3.6M in 2021 to $5.5M in 2024.

Table 5.4-9: Forecast Net System Access Expenditures

Projects	Forecast					Total ($ '000)	% of Total
	2026	2027	2028	2029	2030		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Major Transit Station Area Development (Aldershot GO)	1,258	1,282	654	1,693	1,152	6,039	10%
Major Transit Station Area Development (Burlington GO)	985	1,048	477	2,364	1,608	6,482	11%
Major Transit Station Area Development (Appleby GO)	1,150	1,346	598	1,658	1,893	6,646	11%
Smart Meter Replacement/Reverification	2,600	2,547	2,598	775	748	9,268	15%
Suite Metering	609	587	554	631	643	3,024	5%
Meters - New Connections	408	428	451	473	497	2,257	4%
Metering Infrastructure and Systems	168	208	212	135	138	862	1%
General Service - Overhead	1,199	1,222	1,247	1,271	1,297	6,236	10%
General Service - Underground	1,683	1,716	1,751	1,783	1,821	8,756	14%
Subdivisions	750	728	743	757	773	3,751	6%
Dundas St Road Widening - (Appleby line to Northampton Boulevard)	2,666	604	-	-	-	3,270	5%
Dundas St Road Widening - (Northampton Boulevard to Guelph line)	927	-	-	-	-	927	2%
Transformers – New Connections	354	360	367	375	382	1,838	3%
Other - MTO/City/Region Projects	230	234	239	243	248	1,194	2%
Total Expenditure, Net	**14,986**	**12,312**	**9,891**	**12,161**	**11,201**	**60,551**	**100%**

Question(s):

a) Table 5.4-9 of the DSP contains a forecast of the Net System Access Expenditures for 2026-2030, including forecasted General Service projects. Please provide a source to support the stated increase in reference 1 in Service Upgrades and Connections captured in general Service programs.
b) Burlington Hydro states that the number of net metering customers increased from 25 in 2021 to 127 in 2024. As the Engineering Services role was filled in 2022, please provide the variance in net metering customers from 2021-2022.
c) Burlington Hydro states that there was an increase in the volume of subdivision completions which were $1.6M in 2024 as compared to "$—M" in 2021. Please indicate if the blank space was a typographical error and, if so, provide the updated figure for 2021.
d) Please provide the variance in General Service projects from 2021 to 2022.
e) Burlington Hydro states that without this position, it will face execution risks due to the inability of current staff to manage a larger capital portfolio. The only major difference in system access capital expenditures between 2025 and 2026 is the addition of the MTSA Go Development Projects.
    i. Please provide a detailed explanation of the impacts of a reduction of one employee in the engineering department.
    ii. Has Burlington Hydro experienced delays/reductions in the number of projects they were able to complete in a year in the past? If yes, please provide an explanation.

Response:

a) BHI provides Table 1 below for the forecasted number of Service Connections and Upgrades for the 2026-2030 period in Table 1 below and including the expected growth as a result of the MTSAs identified in Appendix A of the DSP at pages 30-51.

Table 1

Description	2026	2027	2028	2029	2030
Total New connections and upgrades	1,334	1,443	1,553	1,664	1,775

b) The number of net metering customers increased by 30 from 2021-2022.

c) BHI confirms that there were no Subdivision acquisitions in 2021 and hence $-M indicating $0 was stated in the reasoning in Exhibit 4, 4.3.1.1 page 203.

d) BHI provides the variance in General Service projects from 2021 to 2022 in Table 2 below.

Table 2

Program	2021	2022	2022 vs. 2021 $	2022 vs. 2021 $
General Service - Overhead Gross	$853,209	$1,211,639	$358,430	42%
General Service - Underground Gross	$2,520,612	$3,160,148	$639,536	25%
Transformers – New Connections Gross	$193,462	$528,959	$335,497	173%
Total General Service - Gross	**$3,567,282**	**$4,900,746**	**$1,333,464**	**37%**

e)

i. Engineering Service Technicians play a key role in the planning and execution of capital projects across the entire distribution capital program (i.e. System Access, System Service and System Renewal investments). Their duties include design development, standards implementation, project coordination, customer and stakeholder liaison, contract administration, site inspections, inventory management, and overseeing project commissioning and energization. Workloads in all these areas are rising as volume and complexity of the projects that BHI needs to execute is increasing. For example, BHI is experiencing growth in the volume of connections requests and service upgrades as identified in BHI's response to 4-Staff-40 c Table 3; higher load requirements associated with customer-driven projects in the MTSAs as densification occurs (see pages 30 to 51 of the DSP Appendix A), and an increase in System Renewal projects as identified in Section 5.4.1.2.2 of the DSP.

BHI's current resource pool of Engineering Service Technicians is operating near capacity, with limited backup available to manage workload overflows, succession planning, unexpected absences, and anticipated increases in future workloads. Without an adequate number of resources in the Engineering portfolio, including the addition of another Engineering Service Technician as outlined in the evidence, capital projects and customer service requests in the next rate term may experience increased risk of delays. This could affect outcomes such as reliability, connection timelines, grid modernization, and DER enablement.

ii. To date, BHI has not encountered delays/reductions in the number of projects it has been able to complete in a year in the past. BHI has managed deadlines primarily by placing increased demands and strain on current resources within the department. This approach is not sustainable in the long term, as it may lead to employee burnout and/or increased turnover, which could compromise timelines of capital work. Additionally, workforce investment is needed in this portfolio to meet the future challenges outlined in Exhibit 4 (pages 208-212).

4-Staff-52
FTE Count
Ref. 1: Exhibit 4, 4.1.2.1 Salaries and Benefits, Table 5, p. 19
Ref. 2: Chapter 2 Appendices, 2-K Employee Costs
Ref. 3: Chapter 2 Appendices, 2-L Recoverable OM&A Cost per Customer and per FTE

Preamble:

Table 5 of Exhibit 4 indicates that the 2021 OEB-approved number of FTEs was 102, and the 2021 Actuals was 112 FTEs. However, both Appendices 2-K and 2-L of the Chapter 2 Appendices show that the 2021 OEB-approved was 100 FTEs and 2021 Actuals were 110.

Question(s):

a) Please reconcile these figures and provide reasoning for the discrepancy.

Response:

Table 5 of Exhibit 4 is based on FTE at year-end. Appendices 2-K and 2-L of the Chapter 2 Appendices are based on average FTE throughout the year. BHI provides a reconciliation in Table 1 below. Although the average FTE throughout the year is not necessarily a mathematical average of the FTE at the beginning and end of the year, BHI provides a reconciliation below.

Table 1

Description	2021 CoS	2021 Actuals
FTE Beginning of Year	98	108
FTE End of Year (Table 5, Exhibit 4)	102	112
FTE 2-K and 2-L (Average)	**100**	**110**

4-Staff-53
Cyber Security
Ref. 1: Exhibit 1, 1.2.4 C Rate Base and DSP, p. 30
Ref. 2: Exhibit 4, 4.1.2.1 Salaries and Benefits, pp. 14-18
Ref. 3: Exhibit 4, 4.3.0.2, Program Costs, 2025-2026 Variance Explanation, p. 58

Preamble:

In reference 1, Burlington Hydro states that modernizing its grid and operations requires the LDC to continue to invest in cyber security tools and platforms to enhance cyber security readiness in accordance with the Ontario Cyber Security Framework and the OEB's Ontario Cyber Security Standard.

In reference 2, Burlington Hydro summarized the main factors which drove the significant increase in staffing levels from 2021 to 2026. This included mitigating cyber risk by complying with Ontario Cyber Security Framework standards and regulations.

In reference 3, Burlington Hydro cites compliance with OEB cyber security audit requirements, as per the Ontario Cyber Security Framework issued on December 16, 2024, as resulting in a $102,349 increase in 2025-2026 expenditures

Question(s):
Please complete the following tables on capital and OM&A spending between in-house IT solutions and subscription-based models or cloud-based solutions.

> *Please clarify whether the tables requested are related to cyber security IT solutions or all IT solutions. The preamble focuses on Cyber Security references.*
>
> *OEB Staff is requesting information for cyber security-related IT solutions*

Costs for In-house Solutions from 2021-2026

	2021	2022	2023	2024	2025	2026
Capex	$	$	$	$	$	$
OM&A	$	$	$	$	$	$

Costs for Subscription-based/Cloud-based Solutions from 2021-2026

	2021	2022	2023	2024	2025	2026
Capex	$	$	$	$	$	$
OM&A	$	$	$	$	$	$

If applicable, please explain any cost savings as a result of moving to a subscription-based model or cloud-based solutions which Burlington Hydro would otherwise be incurring with in-house solutions.

Response:

BHI provides the Costs for In-house Solutions from 2021-2026 in Table 1 below.

Table 1 – Cyber Security Costs for In-house Solutions from 2021-2026

Description	2021	2022	2023	2024	2025	2026
Capex	$0	$0	$0	$0	$20,000	$25,500
OM&A	$0	$0	$0	$0	$0	$0

BHI provides the Costs for In-house Solutions related to cyber security from 2021-2026 in Table 2 below.

Table 2 – Cyber Security Costs for Subscription-based/Cloud-based Solutions from 2021-2026

Description	2021	2022	2023	2024	2025	2026
Capex	$0	$0	$0	$0	$0	$20,400
OM&A	$0	$0	$0	$0	$114,000	$141,000

There are no feasible in-house or on-premise alternatives to the OM&A investments identified in Table 2 above, and thus no applicable cost savings of moving to a subscription-based model or cloud-based solutions which BHI would otherwise be incurring with in-house solutions.

4-Staff-54
Legal Fees
Ref. 1: Exhibit 4, 4.3.0.2, Program Costs, 2021 Cost of Service application-2021 Variance Explanation, p. 56

Preamble:

Burlington Hydro states that actual expenditures were $169,721 higher in 2021 vs the 2021 OEB-approved, in part due to an increase in Professional Fees of $57,260 resulting from higher than budgeted legal fees in the finance and engineering departments.

Question(s):

a) Please provide an overview of the legal work referenced above and, if possible, provide additional detail on why this legal work was unforeseen.

Response:

a) The legal work relates to:
   - Easements, surveys, and property searches - a higher number of easements were required in 2021 than anticipated in the 2021 Cost of Service – it is difficult for BHI to forecast these amounts with certainty.
   - Legal support for (i) claims from customers and (ii) uncollectible amounts from customers, both of which were higher than anticipated in the 2021 Cost of Service primarily due to three larger claims/uncollectible amounts in 2021. BHI cannot forecast these amounts with certainty.
   - Set up of agreements for the lease of a portion of BHI's head office property – this lease was not known at the time of the 2021 Cost of Service application and as such legal fees were not budgeted for.
   - Set up of TD Bank Loan to BHI (refer to page 7 of Exhibit 5) – the loan was budgeted for in the 2021 Cost of Service but the legal fees were not.

4-Staff-55

Reference:

Ref. 1: Exhibit 4, 4.3.0.12, Information Services, p. 131
Ref. 2: Exhibit 4, 4.1.2.1, p. 17
Ref. 3: DSP, Table 5.4-13
Ref. 4, DSP, SCADA Replacement and ADMS Acquisition, p. 149

Preamble:

In reference 1, Burlington Hydro indicates that Costs associated with upgrades and replacements of IT/OT Infrastructure are included as capital expenditures in the General Plant category

In reference 2, Burlington Hydro indicates that technology upgrade requirements have driven the need to hire additional FTEs.

In reference 4, Burlington Hydro indicates that the estimated expenditure for this project is $3.64M with an expected in-service date of December 31, 2027. This does not include costs associated with integrating with existing Burlington Hydro applications or the cost of field hardware, as Burlington Hydro will be in a better position to accurately forecast these costs as part of the project preparation phase.

Question(s):

a) Has Burlington Hydro conducted any internal reviews of the expected costs? If so, please provide as accurate an estimate as possible of the expected costs associated with integrating existing applications and cost of field hardware.

Response:

a) BHI has not conducted any internal reviews of the expected costs associated with integrating with existing BHI applications or the cost of field hardware. Please refer to 2-Staff-12 f).

4-Staff-56

Reference:
Ref. 1: Chapter 2 Appendices, Appendix 2-JC OMA Programs

Question(s):

a) Where possible, please provide updated year to date actuals for 2025 OM&A costs, in Appendix 2-JC format. Please specify how many months are actual vs. forecast.

   Clarification: OEB staff is asking for full-year revised forecast to 2025 which incorporates YTD actuals.

Response:

a) BHI provides updated year to date actuals for 2025 OM&A costs in Appendix 2-JC format as IR_Attachment_4-Staff-56_BHI_07242025. This includes 5 months of actuals (Jan-May) and 7 months of forecast (Jun-Dec).

4-Staff-57

Reference:
OEB Policy Initiatives and Consultations
Ref. 1: Exhibit 4, 4.1.2.1 Salaries and Benefits, p. 16

Question(s):

a) Please provide a list of the FTEs assigned to each policy initiative and consultation, along with relevant tasks each FTE is directly responsible for and the estimated portion of their normal workload allocated to each policy initiative and consultation.

Response:

a) This question seeks a very granular level of detail that is not readily available and cannot be produced within the timelines of responding to IRs. BHI estimates that up to 15 employees, across up to seven departments, are involved in policy initiatives and consultations, ranging from low involvement (e.g., Electric Vehicle Charging Rates) to significantly higher involvement (e.g. Capacity Allocation Model, publication of Distribution System Capacity Information Map, revisions to Activity Based Benchmarking, Vulnerability Assessments, BCA Framework). Policy initiatives and consultation drive workloads in the following ways:

- Policy development, including identifying, evaluating and incorporating changes to BHI's operations
- Policy implementation and change management including modifying processes and procedures, updating policies, implementing new controls, training, and implementing systems changes to comply with new requirements
- Preparing documentation such as business cases and customer forms
- Verifying data which includes reconciliation across multiple systems, building audit trails into data files and validating or cleansing data to ensure accuracy prior to reporting/publication
- Implementing detailed tracking, analysis, reporting, and monitoring
- Educating consumers and developers including the development of customer-facing material and face-to-face meetings

4-Staff-58

Reference:
Bad Debt
Ref. 1: 4.3.0.6, Customer Service, Table 20, p. 81
Ref. 2: 4.3.0.6, Customer Service, pp. 81-82

Question(s):

a) In Table 20 in reference 1, the actual bad debt expense for 2021-2024 varied from $58k to $200k. Please provide an explanation for how Burlington Hydro determined $150k as the appropriate forecasted bad debt expense for the 2026 Test Year, and how this reflects its historical experience 2021-2024.

Response:

a) BHI based its bad debt expense for the 2026 Test Year on historical customer write-offs which have ranged from $124K to $149K over the past four years (2021–2024) resulting in an average of $136k. Adjusting for inflation, this results in a 2026 Test Year customer write-off amount of approximately $150k. Bad debt expense in Table 20 includes customer write-offs and adjustments to BHI's allowance for bad debts in 2021, 2022 and 2024. No adjustment is expected to be made to BHI's allowance for bad debts in 2025 and 2026.

4-Staff-59

Reference:
Resources to support DERs and NWS
Ref 1: Exhibit 4, p. 8
Ref 2: Exhibit 4, pp. 14-16
Ref 3: Exhibit 2, Appendix A DSP, Part 1 of 3, p. 107

Preamble:

Burlington Hydro Inc has indicated a need for additional resources to meet evolving legislative and regulatory obligations. Reference is made to the Ministry of Energy and Electrification's Letter of Direction to the Ontario Energy Board (OEB), which emphasizes supporting customer choice, addressing barriers to the adoption of Distributed Energy Resources (DERs), and optimizing the use of DERs to meet both provincial and local energy needs. Burlington Hydro has also cited new policy initiatives from the OEB, including the **Benefit-Cost Analysis (BCA) Framework for Addressing Electricity System Needs**. Despite these developments, Burlington Hydro's Distribution System Plan (DSP) states that it is not proposing any Non-Wires Solutions (NWS) for the upcoming rate period.

Question(s):

a) Based on the deployment of these resources, what level of DER adoption does Burlington Hydro anticipate during the upcoming rate period?
b) Please provide an overview of the amounts included in 2026 Capital and OM&A directly related to DERs.

Response:

a) The identified need for additional resources is not tied to meeting a specific DER forecast over the rate period. Rather, it is driven by a strategic long-term priority to support the integration of DERs into its system, consistent with the objectives articulated by the government in its various Letters of Direction to the OEB and in the recent Integrated Energy Plan which provides a roadmap for the next 25-years. To address this longer-term objective of DER integration, BHI must invest in advanced operational capabilities, enabled by technology systems like the ADMS and AMI 2.0 and resources that are skilled (through on the job-training and development) in operationalizing these systems and extracting the value of the data and digital tools that new technologies provide.

b) Please see Table 1 below for a summary of capital investments planned for 2026 that will facilitate DER adoption. Further, BHI plans to invest in a next generation AMI or AMI 2.0 (refer to page 20-23 of Appendix A of the DSP), System Renewal investments in substation relay upgrades (refer to page 65-68 of Appendix A of the DSP) and ADMS replacement/SCADA replacement in 2027 (refer to page 108-115 of Appendix A of the DSP), investments which are essential for BHI to efficiently and effectively manage the distribution system of today and in the future, including facilitating DER adoption.

Table 1 – 2026 Capital Projects Supporting DER Adoption

Project	$000s	DER Impact
MTSA Development (Burlington GO)	2,000	System expansion to bring additional capacity that will facilitate DER connections
MTSA Development (Aldershot GO)	2,000	System expansion to bring additional capacity that will facilitate DER connections
MTSA Development – Tremaine TS Feeder Egress	3,000	System expansion to bring additional capacity that will facilitate DER connections
Residential Smart Meter replacement	1,854	In conjunction with deployment of AMI 2.0 technology that would support DER adoption
AMI Collector System Upgrade	300	Deployment of AMI 2.0 to support future DER adoption

The 2026 Test Year OM&A requests funding for resource additions across numerous portfolio to support DER adoption, including the Supervisor, Energy Transition Integration/DER (p212 of Exhibit 4), the Engineering Services Technician – Energy Transition Integration (p 213 of Exhibit 4), the Regulatory Analyst (p 224 of Exhibit 4), the Financial Analyst (p 206 of Exhibit 4), the Senior Manager of Capital Planning and Supply Chain (p 225 of Exhibit 4), and the Supervisor, System Planning and Grid Modernization (p 217 of Exhibit 4). The total funding necessary to accommodate these positions is approximately $0.9M per year. The rationale for the requirement to fill these positions in the 2026 Test Year is provided in BHI's response to 4-Intervenor-114b). The consequences of not having sufficient funding to fulfil these roles are outlined at page 212 of Exhibit 4 and in BHI's responses to interrogatories 4-Staff-45, 4-Staff-62, 4-Staff-63 and 4-Staff-65, and 4-Intervenor-113.

4-Staff-60
OMERS
Ref 1: Exhibit 1, Appendix G – 2024 Audited Financial Statements, Note 16(a), p.111
Ref 2: Exhibit 4, Section 4.3.1.5, Table 59-OMERS Contribution Costs

Preamble:

Per Ref 1 & 2, OEB staff has compiled a table as below, showing the difference of OMERS costs between Audited Financial Statements (AFS) and Exhibit 4 from 2023 to 2025.

Table (1): Difference of OMERS costs between AFS and Exhibit 4

In '000	2023	2024	2025
OMERS Cost per F/S Note 16(a)-Ref 1	1,202	1,021	1,379
OMERS Cost per Table 59-Ref 2	1,308	1,297	1,379
Variance	106	276	0

Question(s):

a) Please explain the variances identified in the Table (1) above for 2023 and 2024.

Response:

a) BHI identified an error in Table 59 of Exhibit 4 which had an incorrect value in the 2023 and 2024 Actuals, and the 2026 Test Year. BHI provides a corrected version of OEB Staff's Table (1) as Table 1 below, and revised Tables 56, 57 and 58 as Tables 2, 3 and 4 below. None of these errors affected total OM&A as filed in the Application – the amounts reported in OEB Appendix 2-K and 2-JA were correct.

The reason for the variances identified in the revised Table (1) are that the OMERS costs in the audited financial statements (per F/S note 16(a)) are based on budgeted amounts because actual amounts are not available prior to the approval of the audited financial statements. This treatment is consistent year over year.

Table 1 – OEB Staff Table (1) Revised

$000s	2023	2024	2025
OMERS Cost per F/S Note 16(a) - Ref 1	1,202	1,275	1,379
OMERS Cost per Revised Table 59	1,327	1,371	1,379
Variance	125	96	0

Table 2 – Table 56 Revised (for OMERs and to balance to OEB Appendix 2-K)

Type of Benefit	2021 Test Year	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals	2025 Bridge Year	2026 Test Year
CPP - Employer Portion	302,550	361,708	401,070	416,963	455,373	466,106	538,956
EI - Employer Portion	112,567	131,519	139,717	141,533	146,290	155,894	181,718
Employer Health Tax	231,848	250,691	266,787	265,835	270,665	242,016	283,727
WSIB	77,913	83,208	68,873	67,627	67,326	68,479	79,951
TOTAL STATUTORY	724,879	827,127	876,448	891,958	939,655	932,495	1,084,352
OMERS	1,272,687	1,212,994	1,255,473	1,326,506	1,371,261	1,379,179	1,630,776
Health & Dental	818,976	693,431	696,336	750,589	864,282	1,092,738	1,321,728
LTD Insurance	113,914	101,724	117,985	123,851	135,574	155,411	183,000
Life Insurance	35,466	33,282	32,346	35,580	39,507	46,061	54,698
Other	-	97,232	148,433	130,040	134,143	151,938	156,664
TOTAL COMPANY	2,241,042	2,138,663	2,250,572	2,366,566	2,544,768	2,825,327	3,346,866
TOTAL BENEFITS EXPENSE	2,965,921	2,965,789	3,127,020	3,258,524	3,484,423	3,757,821	4,431,218

Table 3 – Table 57 Revised (for OMERs and to balance to OEB Appendix 2-K)

Type of Benefit	2021 Actuals vs. 2021 CoS	2022 vs. 2021	2023 vs. 2022	2024 vs. 2023	2025 Bridge Year vs. 2024	2026 Test Year vs. 2025 Bridge Year	2026 Test Year vs. 2021 Actuals
CPP - Employer Portion	$ 59,158	$ 39,362	$ 15,893	$ 38,411	$ 10,733	$ 72,850	$ 177,248
EI - Employer Portion	$ 18,952	$ 8,198	$ 1,816	$ 4,757	$ 9,604	$ 25,824	$ 50,199
Employer Health Tax	$ 18,843	$ 16,096	$ (952)	$ 4,830	$ (28,649)	$ 41,711	$ 33,036
WSIB	$ 5,295	$ (14,335)	$ (1,246)	$ (300)	$ 1,152	$ 11,472	$ (3,258)
TOTAL STATUTORY	**$ 102,248**	**$ 49,321**	**$ 15,510**	**$ 47,697**	**$ (7,160)**	**$ 151,857**	**$ 257,225**
OMERS	$ (59,693)	$ 42,479	$ 71,033	$ 44,755	$ 7,918	$ 251,597	$ 417,782
Health & Dental	$ (125,545)	$ 2,905	$ 54,253	$ 113,693	$ 228,456	$ 228,990	$ 628,298
LTD Insurance	$ (12,190)	$ 16,261	$ 5,866	$ 11,723	$ 19,837	$ 27,589	$ 81,276
Life Insurance	$ (2,184)	$ (937)	$ 3,235	$ 3,927	$ 6,553	$ 8,638	$ 21,416
Other	$ 97,232	$ 51,200	$ (18,392)	$ 4,103	$ 17,795	$ 4,726	$ 59,432
TOTAL COMPANY	**$ (102,379)**	**$ 111,909**	**$ 115,994**	**$ 178,202**	**$ 280,559**	**$ 521,539**	**$ 1,208,203**
TOTAL BENEFITS EXPENSE	**$ (131)**	**$ 161,230**	**$ 131,505**	**$ 225,899**	**$ 273,398**	**$ 673,396**	**$ 1,465,428**

Table 4 – Table 59 Revised

Description	2021 CoS	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals	2025 Test Year	2026 Bridge Year
OMERS	$ 1,272,687	$ 1,212,994	$ 1,255,473	$ 1,326,506	$ 1,371,261	$ 1,379,179	$ 1,630,776

4-Staff-61

Reference:
Pension and OPEB
Ref 1: Exhibit 4, Section 4.3.1.5, Table 59-OMERS Contribution Costs
Ref 2: Exhibit 4, Section 4.3.1.5, Table 60-Post Retirement Benefits Expense
Ref 3: Chapter2Appendices_2D_Overhead_04162025
Ref 4: EB-2020-0007,
Settlement_Attachment_Main_OEB_Chapter2Appendices_20210317, 2D
Ref 5: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.4.3.1, p.32

Preamble:

Chapter 2 Filing Requirements states that:

> *"The distributor must provide details of employee benefit programs, including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for in the last OEB-approved rebasing application, and for historical, bridge and test years."*

OEB staff has compiled a table as below, showing the capitalized employee benefits to OM&A, the OMERS pension costs and the Post Retirement Benefits in the table below.

Table (A): Capitalized Employee Benefits, OMERS & OPEBs

	2021 Board Approved	**2021 Actual**	**2022 Actual**	**2023 Actual**	**2024 Actual**	**2025 Bridge**	**2026 Test**
Capitalized OM&A (Employee Benefits) (Ref 3 & 4)	579,826	509,804	756,414	752,321	775,462	652,955	793,126
OMERS Pension Cost (Ref 1)	1,272,687	1,212,994	1,255,473	1,307,962	1,297,329	1,379,179	1,630,776
Post Retirement Benefits (Ref 2)	Please fill in the Amount	344,013	365,616	301,666	292,946	337,421	325,589

Per Table (A) above, OEB staff notes Burlington Hydro has quantified the amount of Employee Benefits being capitalized into OM&A. However, it does not indicate the percentage of OMERS pension costs and Post Retirement benefits respectively being capitalized into OM&A.

Question(s):

(a) Please fill in the amount of 2021 Board Approved Post Retirement Benefits in the table above.

(b) Please provide the breakdown of what is included in the “Capitalized OM&A (Employee benefits)” in the table above. Whether this amount includes both OMERS pension costs and Post Retirement benefits? If yes, what is the percentage of OMERS pension costs and Post Retirement benefits respectively being capitalized into OM&A? If not, please explain why they are not included in the capitalized OM&A.

(c) Please provide the breakdown of OMERS pension costs & OPEBs amounts between capital and OM&A from last OEB-approved rebasing application to this test year on a year-by-year basis and explain any significant increase/decrease of the percentage.

Response:

(a) The 2021 Board Approved post-retirement benefits amount was $341,305.

(b) BHI provides a breakdown of what is included in the “Capitalized OM&A (Employee Benefits)” in Table 1 below. These amounts include OMERS pension costs – 17% of OMERS costs are capitalized in the 2026 Test Year. Post Retirement benefits costs are not capitalized because they relate to benefits for retirees and as such cannot be capitalized in accordance with IFRS 16, as they are not directly attributable to bringing any asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Table 1 – Breakdown of Capitalized OM&A (Employee Benefits)

Description	2021	2022	2023	2024	2025	2026
CPP - Employer Portion	62,176	97,017	96,267	101,344	80,990	96,466
EI - Employer Portion	22,607	33,797	32,677	32,557	27,088	32,525
Employer Health Tax	43,092	64,535	61,375	60,237	42,052	50,783
WSIB	14,303	16,660	15,614	14,984	11,899	14,310
OMERS	228,725	347,466	236,761	253,670	210,651	277,921
Health & Dental	98,979	124,669	242,794	243,852	218,867	250,536
LTD Insurance	17,486	28,540	28,595	30,172	27,004	32,754
Life Insurance	5,721	7,824	8,215	8,792	8,003	9,790
Other	16,714	35,905	30,023	29,854	26,401	28,041
Total Benefits	**509,804**	**756,414**	**752,321**	**775,462**	**652,955**	**793,126**

(c) BHI provides the breakdown of OMERS costs between capital and OM&A from the last OEB-approved rebasing application to the 2026 Test Year in Table 2 below. Table 2 below updates 2023 and 2024 total OMERS Pension Costs which were incorrectly stated in Table 59 of the Application.

Table 2 – Breakdown of OMERS Costs

Description	2021 Board Approved	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge Year	2026 Test Year
OMERs Pension Costs	**$1,272,687**	**$1,212,994**	**$1,255,473**	**$1,326,506**	**$1,371,261**	**$1,379,179**	**$1,630,776**
OM&A Portion	$1,041,883	$984,269	$908,007	$1,089,745	$1,117,591	$1,168,528	$1,352,855
Capital Portion	$230,804	$228,725	$347,466	$236,761	$253,670	$210,651	$277,921
% Allocated to OM&A	81.86%	81.14%	72.32%	82.15%	81.50%	84.73%	82.96%
% Allocated to Capital	18.14%	18.86%	27.68%	17.85%	18.50%	15.27%	17.04%

BHI experienced a significant increase in the % of OMERS Pension Costs allocated to capital in 2022. The % of OMERS Pension Costs allocated to capital is directly proportionate to the number of employee hours recorded to, and directly attributable to, capital projects. In 2022, the nature and type of BHI's capital projects required BHI employees to spend a higher percentage of their time on capital versus operating projects. Further details are provided in BHI's response to 4-Intervenor-95 a).

As described above in part b) OPEB amounts are not capitalized.

4-Staff-62

Reference:
Financial Analyst
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Financial Analyst, pp. 206-207

Question(s):

a) Burlington Hydro states that an additional accounting employee is required to ensure in-service assets are componentized, depreciated and allocated to the correct accounts. It also states that the new employee will ensure funds received from, and refunds to, developers for system expansion are recorded and tracked according to DSC and appropriately allocated between capital contributions and expansion deposits.
   i. Can Burlington Hydro confirm if these tasks were done during the historical period
   ii. Please detail the additional tasks due to increased capital expenditures.

b) Burlington Hydro states that this role will support projects that promote digitalization and automation such as the ERP replacement project.
   i. Can Burlington Hydro provide examples of other digitalization and automation projects?
   ii. What is the purpose of the project?
   iii. Does adding a new employee increase efficiency, decrease workload per employee, or both?

Response:

a)

i. BHI confirms that the tasks mentioned in part a) above were performed during the historical period. However as identified on Page 206-207 of Exhibit 4 the requirement for an additional accounting employee is to manage an increase in workload and complexity. These are a result of population and capital growth, and changes to policy and regulations such as the introduction of the Capacity Allocation Model and changes to the connection horizon for the Economic Evaluation Model.

ii. The additional tasks due to increased capital expenditures are as follows, in addition to the tasks of implementing capital projects related to digitalization and automation discussed in part b:

- Journal entries and capitalization reviews
- Tracking a higher volume of expansion deposits, capital contributions, refunds and interest calculations as a result of an increased number of system expansions
- Monitoring, processing, invoicing and closing a higher volume of capital work orders
- Managing and administering the new requirements of Capacity Allocation Model and Economic Expansion Model (connection horizon potential extension to 15 years creates additional workload)
- Business case development for capital infrastructure and developments (financial implications and cost benefit analysis, including the OEB's BCA framework)

b) i. ii. and iii.

The new financial analyst role will support digitalization and automation projects such as the ERP, for the purposes described in Appendix A of the DSP at pages 116-119. Once the ERP is completed, other automation and digitalization projects will be undertaken by BHI, with the support of this resource, including integration of budgeting and forecasting software and workflow processes, such as accounts payable, with the new ERP, data archiving management, forms automation, and application functionality enhancements through custom programming changes.

Adding this resource to BHI's workforce complement enables the successful execution of digitalization and automation projects which will enhance operational effectiveness and efficiency in the organization by streamlining the budget-to-board approval process, ensuring financial plans are easily traceable, facilitating evidence submission for rate setting and rebasing applications, reducing the length of the accounting close cycle, and enabling proactive vs. reactive budget control through real-time dashboarding tools and "drill-down" analytics at the project, department or contractor level.

In some instances this will ease employee workloads by automating manual processes and tasks, creating capacity for employees to complete higher value work and address incremental work requirements without adding more resources.

In other circumstances, automation and digitalization will improve operational effectiveness by enabling employees to:

- automatically record capital expenditures by USoA, work order, WIP and capital program, reducing manual entry and the chance of errors
- auto-generate variance reports for capital expenditures and depreciation on a USoA, work order and capital program basis
- automatically simulate multiple rate scenarios and reforecast budgets based on changes to inflation assumptions or load growth
- automatically prepare OM&A budgets by program and sub-program
- prepare analysis and reports that support more timely and better informed decision-making,

4-Staff-63

Supervisor, Energy Transition

Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Supervisor, Energy Transition Integration/DER, pp. 212-213

Question(s):

a) Burlington Hydro states that the supervisor will facilitate and expedite connection uptake of DERs and EV charging infrastructure. Does Burlington Hydro have data to support this uptake in DERs and EV charging infrastructure?
b) Please provide the number of DER connections from 2021-2025 for each year to date respectively.
c) Please provide the amount of EV charging infrastructure built from 2021-2025 for each year to date respectively.
d) Please explain how the tasks of the Supervisor, Energy Transition Integration/DER were completed previously.

Response:

a) BHI has experienced a steady increase in DER connections and EV charging infrastructure installations as identified in Table 1 and 2 below. These trends are expected to continue over the next rate term as various policy and grid initiatives are undertaken to facilitate the adoption of DERs (e.g. clean energy incentive programs, investment in enabling smart-grid technologies (e.g. ADMS/SCADA, AMI 2.0, intelligent switches etc.) to improve the ability of local grids to integrate DERs, and DSO model to facilitate the optimization of DERs). The Supervisor, Energy Transition Integration will play a critical role in advancing these initiatives and enabling BHI to meet energy policy objectives and resulting regulatory requirements related to DER and EV enablement and integration. To that end, this role will include the following responsibilities:

   Strategic Planning and Integration
   - Develop and implement strategies to integrate DERs (e.g., rooftop solar, battery storage) and EV charging into the local grid.
   - Work with System Planning to conduct feasibility studies and grid impact assessments to ensure safe and reliable integration.

   Project Oversight and Execution
   - Oversee capital projects related to DER interconnections and EV charging station deployment.

- Coordinate with internal engineering teams and external contractors for design, procurement, permitting, and construction.

Technical Leadership

- Provide engineering expertise on grid modernization, smart grid technologies, and load management systems.
- Evaluate and recommend new technologies (e.g., demand response platforms) to support energy transition goals.

Stakeholder Engagement

- Collaborate with municipal planners, developers, and community groups to align infrastructure development with City's sustainability targets.
- Liaise with regulatory bodies like the Ontario Energy Board (OEB) and Independent Electricity System Operator (IESO) on compliance and funding opportunities.

Data and Performance Monitoring

- As and when available, leverage data from deployed digital platforms to monitor DER and EV charging performance, grid impacts, and customer usage patterns.
- Use data analytics to inform optimal grid operations and future infrastructure investments.

Policy and Regulatory Compliance

- Ensure all projects comply with provincial and federal regulations, including net metering, connection standards, and safety codes.
- Contribute to policy development and LDC filings related to DERs and EVs.

Team Leadership and Development

- Supervise engineering staff working on energy transition projects.
- Foster a culture of innovation, safety, and continuous improvement.

b) BHI provides the number of DER connections from 2021-2025 In Table 1 below.

Table 1

Year	Number of DER Connections
2021	6
2022	22
2023	29
2024	34
2025*	8

*YTD June

c) BHI does not have annual data prior to 2023 on the installations of EV charging infrastructure. It also does not have visibility into all EV charging infrastructure installed in its service territory. It does have access to the EV charging infrastructure installations which were connected through the ESA permit process. Between January 1, 2019 to October 1, 2023, a total of 676 ESA permits were issued for residential/commercial EV connections in the City of Burlington. Table 2 below identifies the number of new EV charging infrastructure installations between 2023 and 2025 based on ESA permits issued..

Table 2

Year	Number of New EV Infrastructure
2023	98
2024	697
2025*	311

*YTD June

The above data includes both residential and commercial EV chargers. It also includes upgrades to existing EV chargers (e.g. from Level-1 to Level-2).

d) In the absence of a dedicated Engineering Supervisor, Energy Transition, some of the tasks identified in part (a) of this response are distributed across the existing portfolios within the engineering department, namely Customer Connections, System Planning, Asset Management, and Engineering Design. Further, other tasks are not being performed because of resource constraints, such as centralized project oversight, technical leadership, data and performance monitoring, and team leadership and development. As applications for DER and EV connections rise and integration requirements grow, dividing responsibilities among multiple portfolios becomes less effective. Centralizing these tasks under the proposed Supervisor role is necessary to maintain robust oversight, coordination with stakeholders, and management of evolving team training needs. To that end, the Supervisor, Energy Transition Integration, will:

- Lead cross-functional teams to align DER/EV initiatives.
- Oversee shared data platforms for customer requests, grid performance, and project tracking.
- Lead DER-related project planning, timeline and resource management efforts.
- Guide ongoing training to keep all teams apprised of relevant developments in DER/EV technologies, customer needs/requirements and regulations.

4-Staff-64

GIS Technician

Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, GIS Technician, pp. 214-215

Question(s):

a) Burlington Hydro states the GIS Technician position is critical for increasing regulatory requirements such as publishing a map on its website.
   i) Does Burlington Hydro currently have an outage map present on their website? If so, does it differ from this map?
   ii) The GIS Supervisor is also working on mapping. Will they be working together on this project? If yes, please state the need for both employees to simultaneously be working on this project.

b) Burlington Hydro states that these roles were vacant due to the previous engineering employees being transferred to the IT/OT department. Burlington Hydro stated that these employees were transferred to enhance IT/OT governance. Please explain why an employee in IT/OT could not be promoted to or tasked with completing these roles.

c) Burlington Hydro states that one of the implications of not having a dedicated GIS team would be poor asset management and maintenance which can lead to equipment failures and increased repair costs. Burlington Hydro previously had poor reliability and large amounts of equipment failures during the historical period while these roles were filled by employees who were later moved to the IT/OT department. How does Burlington Hydro plan to change this trend in the forecast years?

Response:

a) The GIS Technician will be critical for implementing and maintaining the Distribution System Capacity Information Map – Phase 2 Implementation, which requires LDCs to standardize information reporting to include feeders operating at 4kV and above, and ensure compliance with the OEB's mandate. The outage map that BHI currently offers on its website is not the same as the capacity map noted above.

   While both GIS Technicians and GIS Supervisors are involved in developing and maintaining system maps, their roles differ significantly in terms of scope, responsibility, and leadership. The GIS's Technician focuses on execution and technical support while the GIS Supervisor provides strategic direction, oversight and leadership of this function. Below is a breakdown of their respective responsibilities and required skills:

<u>GIS Technician:</u>

Responsibilities:

- Collecting, inputting, and updating spatial and attribute data.
- Creating and editing maps using GIS software (e.g., ArcGIS, QGIS).
- Performing spatial analysis and data queries.
- Maintaining GIS databases and ensuring data accuracy.
- Supporting field data collection using GPS or mobile GIS tools.
- Producing standard map products and reports.

Skills:

- Technical proficiency with GIS tools.
- Attention to detail and data accuracy.
- Task-oriented execution.

<u>GIS Supervisor</u>

Responsibilities:

- Overseeing the work of the GIS technician
- Planning and managing GIS projects and timelines.
- Coordinating with other departments or stakeholders.
- Ensuring data standards, quality control, and best practices.
- Budgeting, resource allocation, and procurement of GIS tools.
- Developing long-term GIS strategies and system improvements.

Skills:

- Leadership and project management.
- Strategic planning and decision-making.
- Communication and coordination across teams.

b) The two employees that were transferred from Engineering to the IT/OT department performed a substantial amount of OT work as part of their daily duties. These duties included:

- Implement, maintain, coordinate, support applications/protocols associated with GIS such as CIS, OMS application, and Asset Inspection.
- Liaison between various departments/vendors to coordinate and administer software deployments, application testing, licenses, change requests, and bug fixes.
- Support the team in translating product needs into enhancements and or fixes for the supported application.
- Provide actionable recommendations based on data analysis to drive informed decision-making and strategic initiatives, emphasizing the interpretation of insights to guide organizational goals.
- Collect data from GIS and OMS digital sources and aggregate to create comprehensive datasets for analysis.

- Design and develop analytic dashboards using reporting development tools i.e. SSRS, SSIS, SSAS and Power BI.
- Create comprehensive documentation for OMS and GIS data / reporting processes, including step-by-step guides and best practices, regularly update documentation to reflect changes and improvements in processes.

The integration of experienced engineering personnel with OT expertise into the IT/OT department improved alignment between these functions at BHI and eliminated duplication of personnel that would have been necessary across these portfolios to preserve critical institutional knowledge and continuity related to OT systems.

Through this integration, the IT team gained enhanced visibility into and a deeper understanding of the OT systems, enabling them to achieve the following improved outcomes, which would not have otherwise been possible:

- Eliminated overlap of duties across engineering and IT. Consolidating IT with OT has enabled streamlined workflows, with fewer redundancies and better coordination between support teams, leading to faster problem resolution and more proactive system maintenance. In some cases, patching of systems and licenses were inadvertently duplicated.
- It has allowed for a unified approach to identifying vulnerabilities and implementing robust cyber security protocols across both infrastructures and systems.
- Combining both OT and IT has helped to facilitate cross training between IT staff and transfer of critical institutional and technical knowledge, enabling staff to develop a broader skillset and create a more versatile team. As such risk is mitigated if staff leave the organization.
- Communications across BHI has improved with unified oversight which helps to prevent system downtime and improve reliability through comprehensive monitoring and coordinated investment in new technologies.
- It has created more agility in adopting digitalization and new technologies as the integration of OT and IT can more rapidly deploy and support innovations such as ADMS, smart field devices, and advanced GIS platforms to meet evolving business and customer needs.
- It has improved data and asset management as data and processes are now centralized to assist with informed decision-making regarding maintenance and upgrades.
- The alignment will improve customer outcomes such as responsiveness to outages, and the integration of customer-owned assets like DERs.

c) BHI has included several investments in its Application to address its declining reliability and increased number of equipment failures as identified below.

- Investments to improve reliability as identified in Section 5.2.1.2.2 System Renewal of the DSP (e.g. Cable, transformer and pole replacements)
- Investments to improve reliability as identified in Section 5.2.1.2.3 System Service of the DSP (e.g. Intelligent switches and next generation AMI)
- Investments in ADMS and related technology as identified in Section 5.4.1.2.4 General Plant of the DSP

In addition, with the adoption of new technologies for back-office support (including increasing system automation through platforms such as ADMS, and as smart field are deployed to enable interoperability with customer-owned behind-the-meter assets (such as DERs and BESS devices), it will be necessary to enhance GIS functionality.

Improvements will focus on supporting a robust connectivity model, introducing advance mapping paradigms such as user interactive maps across diverse platforms and interfaces, and enabling comprehensive device tracking and asset health/risk monitoring protocols. This will require skilled GIS resources to implement these enhancements and provide technical and operational support to system operators and IT teams to help maintain a 24/7 active ADMS platform.

These GIS enhancement investments will support BHI in managing reliability and other customer outcomes in the following ways:

- improve asset visibility, condition tracking, and maintenance scheduling.
- Integrate GIS with SCADA, AMI, and outage management systems to enable predictive maintenance and faster fault detection.
- support DER hosting capacity maps, EV charger planning, and strategic targeting of vegetation management
- enhance monitoring of reliability metrics (i.e. SAIDI/SAIFI/CAIFI) for timely intervention to avert system risks from defective equipment.
- enhance the condition and risk-based inspection and maintenance programs using GIS and sensor data.

4-Staff-65

Reference:
Supervisor, System Planning and Grid Modernization
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Supervisor, System Planning & Grid Modernization, pp. 217-218

Question(s):

a) Burlington Hydro has stated that this role will help in assisting and implementing SCADA system upgrades. Burlington Hydro has previously stated that the IT/OT department will be assisting in SCADA system upgrades.
   i) Will this role be working together with the IT/OT department?
   ii) Please provide an explanation as to why an additional employee is needed for SCADA implementation if the project will only be taking place in the 2027 forecast year.

b) Burlington Hydro has stated that if it does not receive funding for this position, it will face delays in system projects due to lack of demand forecasting, increased risks of higher outage impacts to customers and an inability to manage risks around growth and electrification.
   i) The MTSA projects are scheduled to begin in 2026. Has Burlington Hydro completed any demand forecasting for these projects in the 2026 test year?
   ii) Burlington Hydro is already facing a larger amount of outages from the last rebasing period. Are there any significant changes occurring to mitigate this? How will this position directly impact the amount of outages?

Response:

a)

i) Yes, this role will work collaboratively with the IT/OT department to plan and execute the SCADA Replacement and ADMS Acquisition project and manage the operational aspects of the forthcoming systems once implemented. The IT/OT department and the Supervisor of System Planning and Grid Modernization have different areas of expertise and focus, which are both needed to ensure the effective implementation of the SCADA Replacement and ADMS Acquisition project. The IT/OT department primarily focuses on project management and technical aspects of the systems, such as managing the hardware, software, network infrastructure, and cybersecurity requirements. By contrast, the Supervisor of System Planning and Grid Modernization is responsible for the operational aspects of the SCADA system, including to ensure that the SCADA functionality aligns with and is serving the operational needs of the distribution system, supports demand forecasting, and is being implemented in a manner that best supports current and future growth, DER integration, electrification, and outage mitigation strategies. The Supervisor of System Planning and Grid Modernization is essential to effectively planning, implementing, and operating SCADA and ADMS systems in these ways:

- Work with IT/OT department and project manager/team to develop the project roadmap that aligns SCADA and ADMS systems with BHI's broader digitalization and technology objectives. This includes detailed scheduling, resource allocation, and risk assessments to address complex factors such as rapidly growing customer demand, electrification, and distributed energy resource (DER) integration.
- Coordinate with other engineers, IT specialists, and field supervisors to ensure that new hardware and software components are deployed efficiently, thoroughly tested, and fully integrated into the utility's existing infrastructure.
- Leverage advanced SCADA data to conduct ongoing demand forecasting and load analysis, critical for proactive planning. By anticipating system stress points and enabling timely system upgrades, this role directly contributes to mitigating outage risks and minimizing customer impact.
- Work on grid network modeling, load / voltage analysis, alarm and telemetry review, and assist in outage and switching planning.
- Support integrating any systems and processes with future DSO models or programs

ii)

This role is required in 2026 to support and to conduct necessary preparatory work and analysis in advance of the SCADA Replacement and ADMS Acquisition and implementation in 2027. This includes analyzing data from the existing SCADA system, assessing distribution system conditions, and performing demand forecasting, to inform the transition to the new SCADA and ADMS systems. This work will ensure that the new systems are implemented in response to operational needs and are fit to achieve reliability and outage mitigation strategies and objectives. Insufficient staffing increases the risk of outages and compromises BHI ability to deliver this project on time and on budget.

In order for the role to effectively contribute to the project and to ensure the successful execution of the SCADA and ADMS systems, comprehensive training and onboarding prior to implementation are essential as follows:

- To gain necessary technical, operational, and safety knowledge to navigate the complexities of these systems.
- Become acquainted with BHI and industry standards and processes.

- Acquire in-depth knowledge on the architecture, functionalities, and integration points of both legacy and new SCADA and ADMS systems.
- Understand operational requirements of BHI's distribution system, including load forecasting, outage management, and distributed energy resource (DER) integration.
- Be able to contribute to the testing, commissioning, and validation of new SCADA and ADMS components, working alongside IT/OT and field teams to ensure seamless integration with existing infrastructure.

BHI would also like to take this opportunity to reiterate what is outlined in the pre-file evidence at page 217 of Exhibit 4. In addition to the SCADA/ADMS related-work, the Supervisor of System Planning and Grid Modernization will also be responsible for supporting the development and execution of short and long-term system planning initiatives to enhance the capacity and enable the modernization of the grid to support electrification. This mandate includes initiatives such as:

- implementing advanced protection and control schemes to enable DER integration (refer to pages 129, 142 and 161 of the DSP); and

- capacity planning enhancements and work necessary to support growth in BHI's service territory, including investments in the MTSAs (refer to page 121 of the DSP).

b)

i)

Yes, the scope of the expansion projects for servicing MTSAs was developed based on an initial demand forecast using available information from the City of Burlington and the Development community, but the connections resulting from the expected growth in population and construction of 29,000 new residential housing units by 2031 are not reflected in the 2026 load forecast. Please refer to the response to 4-Staff-41 which explains the need for the planning and design phases of these infrastructure projects to commence in 2025 and continue beyond in order to meet the customer connection timelines of 2028 - 2031. In addition to the work that has already been done to support growth in the MTSAs, the Supervisor of System Planning and Grid Modernization is responsible to assess, on an on-going basis, the impact of new, un-forecasted loads specifically in growth intensive areas such as MTSAs, as and when they materialize and devise strategies to:

- Minimize the impact on existing customers through load transfers by moving existing switch open points;
- Identify new switching locations to maintain overall reliability and develop associated capital project plans

- Safely connect the new load;
- Carry out load flow studies to identify system constraints (e.g. thermal loading, feeder size, number of circuits etc.)
- Assess the continued viability of the expansion plans in light of the evolving customer demand within the MTSAs,
- Maintain an updated load forecast taking into account the dynamics of changing economic activity, population growth, electrification trends etc.
- Advise customers on available alternatives based on latest system configurations and loading

ii) The Supervisor, System Planning & Grid Modernization will play a pivotal role in enhancing system reliability through involvement in the following initiatives:

- Proactively identify system impacts from aging or overloaded assets and recommend solutions to reduce the risk of unplanned outages and improve system uptime. For example, replacing transformers or upgrading feeders based on forecasted load growth.
- Through data analysis, leverage outage history, load forecasts, and asset health data to prioritize investments and planning. For example, reinforcing circuits in areas with frequent weather-related outages.
- Plan for and coordinate deployment of smart grid technologies such as automation, sensors, and remote switching. This enables faster fault detection, isolation, and restoration (FLISR) which would lead to a more responsive system to abnormalities and mitigate risk of longer outage durations for customers.
- Perform analysis to ensure that the grid can accommodate DERS such as renewable distributed generation projects (solar), batteries, and EVs without instability. This will enhance the availability of the distribution system to accept a variety of new connections with minimum impact on existing customers. For example, planning for bi-directional power flows and voltage regulation.
- Develop scopes and business cases for capital plans that aligns system needs with customer expectations, operability and engineering technical requirements /standards. This role coordinates project execution.
- Identify critical load areas and plans for redundancy in order to maintain service during equipment failures or extreme events. For example, designing looped systems or backup feeders for critical loads such as hospitals and emergency services.
- Track reliability KPIs and adjust plans based on performance trends using reliability indices (SAIDI, SAIFI, CAIDI) to guide capital planning.

4-Staff-66

Reference:
Supervisor, HR
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Supervisor, HR Analyst/Generalist, p. 222

Question(s):

a) Burlington Hydro states that the current in-house team does not have the expertise/skills to conduct data analysis, develop and maintain HR metrics, or track their effectiveness to support data driven decision making. Please clarify if this is the main task associated with this role. Has Burlington Hydro considered having an employee from the engineering or IT/OT department work alongside the HR department to complete these tasks?
b) Burlington Hydro states that this role will deliver hands-on support for HR program implementation and initiatives, offering client-centered HR solutions. Is this currently being conducted by existing employees? If so, please explain the major changes which will take place when adding this role.

Response:

a) No, the majority of the work for this role will be tasks associated with the broader stewardship of employee engagement initiatives; labour and employee relations; recruitment, selection, and retention, performance management; attendance and disability management; total rewards; and training and onboarding. Even if data analysis, developing and maintaining HR metrics, and tracking their effectiveness to support data driven decision making could be supported to by employees in IT/OT or other programs, it would not be advisable to allocate this work to these employees because of the sensitive nature of HR-related information, and due to their lack of expertise and necessary context to analyze the data in a manner that supports the main objectives of the program.

b) Current aspects of HR program implementation and support are managed by a combination of existing HR team members, who balance these responsibilities alongside their primary duties such as Labour Relations, Recruitment and Payroll. The introduction of the HR Generalist/Analyst role will allow for the HR program to perform their work in an effective and sustainable manner. The HR program is facing increased workloads in a manner that is not sustainable and that does not promote proactive HR solutions. Further, adding this role will improve performance in the HR portfolio.

   For example, effectively addressing employee turnover is a critical component. BHI has incurred high turnover rates on average of 11.3% (refer to Figure 12 on page 191 of

Exhibit 4), which has been disruptive to the organization. It has caused increasing recruitment and training costs, and negatively impacted morale and productivity for employees that pick up the workload of employees leaving or have to retrain new employees. The elevated turnover rate has placed significant additional strain on the HR team, making it increasingly challenging to maintain stability and continuity within the organization. This persistent state of reaction—constantly recruiting and training new employees—prevents the team from investing in proactive, long-term HR initiatives that would help break the cycle of turnover. Furthermore, when employees feel disconnected from leadership or dissatisfied with their roles, departures and workplace conflicts become more frequent. As a result, there has been a noticeable increase in workplace investigations and a greater need for focused, consistent attention to HR program delivery.

By introducing this new HR Generalist/Analyst role, BHI will be better equipped to deliver coordinated, dedicated support across all HR functions, enhance service quality, and drive meaningful improvements in employee engagement, retention, and organizational performance. Reducing turnover can foster a more stable and motivated workforce. It will enhance institutional knowledge, strengthen team cohesion, and position BHI as an attractive employer to top talent in the industry.

4-Staff-67

Reference:
Supervisor, Facilities
Ref. 1: Exhibit 4, 4.3.1.1 Workforce Planning, Supervisor, Facilities Specialist/Coordinator, pp. 226-227

Question(s):

a) Burlington Hydro states that on average, over 80 reactive maintenance issues arise annually. Please provide the number of reactive maintenance issues which have happened in each of the historical years and the 2025 bridge year to date respectively.
b) Burlington Hydro states that these tasks cannot be completed by the facilities manager. Please confirm if the other two positions in safety assist with these tasks.

Response:

a) BHI provides the number of reactive maintenance issues which arise annually in Table 1 below.

Table 1 - # of Reactive Maintenance Issues

Year	Reactive Maintenance Issues Annually
2021	52
2022	83
2023	86
2024	110
2025	62 (YTD June 30, 2025)

b) BHI would like to clarify that the referenced evidence should have stated that these tasks cannot be completely *solely* by the Facilities manager. BHI confirms that the positions in safety do not assist with these tasks.

BHI maintains and secures a head office, 32 substations buildings and properties throughout the City of Burlington. Resources supporting the Facilities program need to have a robust understanding of regulations related to building codes, rapid on-site diagnosis, and immediate remediation skills.

In recent years, the steadily rising number of reactive maintenance issues (averaging over 80 annually and expected to exceed 120 in 2025) has made it increasingly difficult to keep up with the work requirements in this portfolio using current staffing levels.

Furthermore, recent incidents of theft have posed additional security risks introducing greater complexity in managing the facilities portfolio. Addressing these requirements requires specialized knowledge of building systems such as HVAC, plumbing, structural, security and access, electrical, mechanical controls of BHI facility's infrastructure.

With growing and more complex facility needs, BHI needs to invest in a new Facilities FTE to meet the program demands. Assigning these extra duties to the existing Facilities Manager without proper support is not a sustainable solution because it may result in this resource being overstretched potentially impacting project timelines, efficiency, and health and safety outcome.

Assigning these duties to current safety staff is also impractical, as their skills are not easily transferable. Furthermore, effective safety programs demand dedicated focus for tasks like developing policies, hazard identification, risk assessment, regulatory compliance, staff training, performance monitoring, incident investigation, and keeping up with safety legislation.

5-Staff-68

Reference:
Ref. 1: EB-2024-0063 Cost of Capital Decision, March 27, 2025, p. 65
Ref. 2: Chapter 2 Appendices, 2-OA Capital Structure

Question(s):

a) Please revise Appendices 2 - OA Capital Structure to show the Capitalization Ratio (% and $), Cost Rate (%), and Return ($) of both Notional Long-term Debt and Actual Long-term Debt, as shown below.

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt (Notional)				
Long-term Debt (Actual)				
Short-term Debt				
Total Debt	60.0%			
Equity				
Common Equity				
Preferred Shares				
Total Equity	40.0%	$ -		$ -
Total	100.0%			

Response:

a) BHI provides Appendix 2 - OA Capital Structure to show the Capitalization Ratio (% and $), Cost Rate (%), and Return ($) of both Notional Long-term Debt and Actual Long-term Debt in Tab “App.2-OA w Notional Debt” of Attachment_OEB_Chapter2Appendices_BHI_07242025. Actual Long-term Debt and Notional Long-Term Debt are priced at the same Cost Rate since BHI’s weighted average cost of long-term debt is lower than the Deemed Long Term Debt Rate (“DLTDR”) at the time of debt issuance.[1] This calculation is provided in Table 1 below and reflects the changes identified in 5-Staff-70a).

BHI’s weighted average cost of long-term debt is 4.36% as compared to the DLTDR at the time of issuance of 4.40%.

[1] p 64-65, EB-2024-0063 Decision and Order, March 27, 2025

Table 1 – Comparison of Actual LTD Rate to DLTDR

Description	Lender	Start Date	Principal	Cost at Actual Debt Rate		Cost at DLTDR at Time of Issuance	
				Actual Rate	Actual Interest Cost	DLTDR	DLTDR Interest Cost
Promissory Note	City of Burlington		47,878,608	4.51%	2,159,325	4.51%	2,159,325
Debenture	Infrastructure Ontario	March 15, 2011	114,110	4.51%	1,715	5.48%	6,253
Promissory Note	Infrastructure Ontario	March 8, 2013	4,761,720	4.02%	191,421	4.03%	191,897
Promissory Note	Infrastructure Ontario	December 17, 2018	3,991,312	3.63%	144,885	4.16%	166,039
Term Loan	TD Bank	March 31, 2021	2,549,641	2.47%	62,976	2.85%	72,665
Term Loan	TBD	January 1, 2026	9,633,504	4.60%	443,141	4.51%	434,471
Total/Average Rate			**68,928,894**	**4.36%**	**3,003,464**	**4.40%**	**3,030,650**

5-Staff-69

Reference:
Ref. 1: 2021 BHI Settlement Proposal, p. 18 of 54
Ref. 2: Exhibit 5, Section 5.2.4.5

Preamble:

In 2021 Burlington Hydro's Settlement Proposal, the parties agreed to adjust the long-term debt rate on the $5M credit facility with TD bank from 2.85% to 2.227%. In Reference 2, Burlington Hydro stated it made a drawdown from TD at a fixed rate of 2.47%.

Question(s):

a) Please explain the variance in rates between Reference 1 and Reference 2.

Response:

a) The rate of 2.227% (Reference 1) agreed to in BHI"s Settlement Proposal was an estimate based on average indicative rates at the time of the settlement conference (February 22-24. 2021). BHI had not activated the credit facility or locked in an interest rate at that time. When BHI activated the credit facility, effective March 31, 2021, the rate was 2.47% (Reference 2), higher than 2.227% due to rising interest rates.

5-Staff-70

Reference:
Ref. 1: Exhibit 5, p.7
Ref. 2: Chapter 2 Appendices, 2-OB, Debt Instruments

Preamble:

In Reference 1, Burlington Hydro states it plans to make another drawdown in the amount of $10,000,000 on or about July 1, 2025, at a fixed rate of 4.51% expiring July 1, 2035. Burlington Hydro expects to issue new term loan in 2026 in the amount of $10,000,000 to support its ongoing capital expenditure requirements as presented in this Application.

Question(s):

a) Has Burlington Hydro secured the loans of $10M (starting 2025) and $10M (in starting 2026) with the third-party lenders yet?
   i) If so, please update 2026 Debt Instruments table (Appendix 2-OB) to reflect updated information.
b) Has Burlington Hydro considered renegotiating the contract with the City of Burlington or other financing strategy to reduce the interest rate? Please explain.
c) Has Burlington Hydro considered additional options such as an Interest Only loan or comparing offers from other banks?

Response:

a) BHI has access to a credit facility with TD Bank for a remaining $10M which expires December 31, 2026. BHI has not drawdown the remainder of the credit facility or locked in an interest rate. BHI does not expect to drawdown the credit facility in 2025. Further, BHI has received an updated quote for the debt rate, which is 4.60% based on a 10-year term and 10-year amortization (as at July 8, 2025). BHI has updated OEB Appendix 2-OB accordingly, included in Attachment_OEB_Chapter2Appendices_BHI_07242025.

   BHI has not secured the loan of $10M starting in 2026 with third-party lenders yet; however it will consider using the credit facility with TD Bank if rates are competitive.

b) The interest rate on the promissory note with the City of Burlington is set at the Deemed Long-Term Debt Rate set by the OEB in effect at the time of the Cost of Service decision. BHI did not consider renegotiating the contract with the City of Burlington over the 2021-2025 rate term as the interest rate was 2.85%, well below market interest rates. BHI may consider renegotiating the contract with the City of Burlington or other financing strategies in the future.

c) BHI will consider additional options prior to securing future loans.

<u>5-Staff-71</u>

Reference:
Ref. 1: Exhibit 5, Historic Return on Equity, p. 9

Question(s):

a) Please provide the ROE achieved for 2024 if it is available.

Response:

a) BHI's achieved ROE for 2024 was 9.52%.

6-Staff-72

Reference:
Ref. 1: Chapter 2 Appendix 2-H, Account 4405
Ref. 2: Chapter 2 Filing Requirements, Section 2.6.3, May 7, 2025

Question(s):

a) Please confirm whether Account 4405 contains interest amounts related to DVAs or not.
   i) If so, please revise Appendix 2-H to remove any interest amounts associated with DVAs as required in Reference 2.

Response:

a) BHI confirms that Account 4405 does not contain interest amounts related to DVAs.

6-Staff-73

Reference:
2024 Tax Return
Ref 1: Exhibit 1, Appendix G – 2024 Audited Financial Statements (AFS)
Ref 2: Exhibit 6, Section 6.2.1.1 Tax Returns
Ref 3: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.6.2.1, p. 41

Preamble:

OEB staff notes that Burlington Hydro included 2024 AFS in this application while 2024 Federal and Provincial tax return is not submitted in this application.

Question(s):

a) Please provide final 2024 Federal and Provincial tax returns per Ref 3 when it is available.
b) Please confirm that there are no impacts on the 2024 PILs between the draft version and the final version filed with the CRA (in the event that the draft version of the tax return is different from the final version).

Response:

a) BHI provides the final 2024 Federal and Provincial tax returns as IR_Attachment_6-Staff-73a_BHI_07242025.

b) BHI updates its 2024 PILs in Attachment_2026_PILS_Workform_BHI_07242025 in response to 1-Staff-1, to align with the final 2024 Federal and Provincial tax returns.

6-Staff-74

Reference:
Loss Carry forwards
Ref 1: Exhibit 6, Section 6.2.1.2 Loss Carry Forward
Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.6.2, p. 41

Preamble:

Chapter 2 Filing Requirements states that:

> *"Distributors are expected to exercise sound tax planning and are expected, for rate-setting purposes, to maximize tax credits and take the maximum deductions allowed."*

In Ref 1, Burlington Hydro states that it does not expect to apply the amount of $85,869 which is the capital loss carry-forward at December 31, 2024 in 2025 or in 2026.

Question(s):

a) Please provide the nature of this capital loss carry forward.
b) Please explain why Burlington Hydro does not apply the loss carry forward to the test year PILs.

Response:

a) The capital loss resulted from a disposition of capital property in a historical tax year.

b) Capital losses can only be applied against capital gains. As there are no capital gains in the Test Year against which the capital loss can be used, this capital loss is carried forward until such time that BHI realizes a capital gain.

6-Staff-75

Reference:
Tax Credits
Ref 1: Exhibit 6, Section 6.2.1.3 Calculation of Tax Credits
Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.6.2.1, p. 41

Preamble:

Chapter 2 Filing Requirements states that:

> *"The distributor must provide a calculation of tax credits (e.g., Apprenticeship Training Tax Credits, education tax credits, Ontario Regional Opportunities Investment Tax Credits)."*

In Ref 1, Burlington Hydro states that SR&ED related investment tax credits in 2026 PILs model were calculated using the average eligible SR&ED expenditures from 2020-2023, adjusted based on reasonable expectations of future eligible expenditures. The apprenticeship credit and the co-operative education tax credit were calculated using the average credits claimed from 2020-2023.

Question(s):

a) Please explain why Burlington Hydro did not include 2024 claimed amounts for the above-mentioned credits in the calculation of the test year's credit amounts. Please update the credit amounts as applicable.
b) Please provide the nature of the reasonable expectations of future eligible SR&ED expenditures indicated in Ref 1.

Response:

a) SR&ED credits are earned in a year in which a claim is submitted. SR&ED credits in a given year can vary significantly and are dependent on the nature and eligibility of the projects being performed in each taxation year. At the time of submission, the 2024 SR&ED claim was not complete. Therefore, the actual SR&ED credits earned in the 2024 taxation year were not available at that time.

   The 2024 SR&ED claim was finalized in June 2025. In the 2024 tax year, BHI earned a total of $74,817 in SR&ED credits ($14,568 Ontario Research and Development Tax Credit and $60,249 Federal Investment Tax Credit from SR&ED expenditures).

BHI provides an updated PILS model as Attachment_PILS_Workform_BHI_07242025 in its response to 1-Staff-1, to reflect the SR&ED credits earned in 2024 in the Historical year. BHI has considered the impact of these credits in the 2026 Test Year and applied the credits as explained in part (b) below.

b) The SR&ED estimate for the 2026 Test Year was based on the historical eligible expenditures claimed by BHI in its SR&ED claims. As the 2024 SR&ED claim was not available until June 2025, consideration had to be given to the nature of the projects that could give risk to future claims in order to determine an appropriate amount to include in the 2025 Bridge Year and the 2026 Test Year. BHI has updated the Historical year to include the actual SR&ED claim for 2024. In addition, BHI has updated the 2025 Bridge Year and 2026 Test Year to include the average historical claim of eligible expenditures from the 2020 to 2024 taxation years. The Federal Apprentice Job Creation Investment Tax Credit and the Ontario Co-operative Education Tax Credits have also been updated to reflect the average credit earned from 2020 to 2024. BHI provides an updated PILS model as Attachment_PILS_Workform_BHI_07242025 in its response to 1-Staff-1.

6-Staff-76

Reference:
PILs Model
Ref 1: Attachment8_2026 PILs Workform_20250416
Ref 2: Chapter2Appendices_2BA_ Fixed Asset Cont_04162025

Preamble:

Per Ref 1 & 2, OEB staff has complied a table as below, showing the difference of capital additions between PILs model (Schedule 8) and Appendix 2BA (before CWIP addition and excluding land)

Table (1): Difference of Capital Additions between PILs (Sch8) & 2BA

	Bridge Year (2025)	Test Year (2026)
Capital additions per the PILs model (Ref 1)-a	13,302,572	28,596,285
Capital additions per Appendix 2BA (Ref 2)-b	18,502,819	24,271,846
Variance (b-a)	5,200,247	(4,324,439)

Question(s):

a) Please reconcile and explain the variances identified in the table above.

Response:

a) BHI provides a reconciliation of the difference in capital additions between the PILs model and OEB Appendix 2-BA in Tables 1 and 2 below. Table 1 represents the capital additions as filed April 16, 2025 (the Application) and Table 2 represents the capital additions as filed July 24, 2025 (Interrogatory Responses).

Table 1 – as filed April 16, 2025

Description - As Filed April 16, 2025	2025	2026
Capital Additions per Appendix 2-BA	**$18,502,819**	**$24,271,846**
Deduct: Capitalized Overhead in 2-BA deducted for tax purposes	-$296,578	-$296,578
Deduct: SR&ED Capitalized in 2-BA deducted for tax purposes	-$141,326	-$141,326
(Deduct)/Add: Adjustment to Class 47 (ICM Dundas Road Widening)	-$4,762,343	$4,762,343
Capital Additions per the PILs Model	**$13,302,572**	**$28,596,285**

Table 2 – as filed July 24, 2025

Description - As Filed July 24, 2025	2025	2026
Capital Additions per Appendix 2-BA	**$17,903,861**	**$24,917,000**
Deduct: Capitalized Overhead in 2-BA deducted for tax purposes	-$289,483	-$289,483
Deduct: SR&ED Capitalized in 2-BA deducted for tax purposes	-$136,546	-$136,546
(Deduct)/Add: Adjustment to Class 47 (ICM Dundas Road Widening)	-$4,762,343	$4,762,343
Capital Additions per the PILs Model	**$12,715,489**	**$29,253,314**

6-Staff-77

Reference:
Other taxes
Ref 1: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.6.2.2, p. 43
Ref 2: Exhibit 6, section 6.2.2 Other taxes, p. 20

Question(s):

a) Please clarify in which account the property tax was recorded per Ref 1.
b) Please confirm that the property tax is excluded from OM&A expense on the RRWF.

Response:

a) BHI recorded property tax in Account 6105.

b) BHI confirms that it excluded property tax from OM&A expense on the RRWF.

6-Staff-78

Reference:
Accelerated CCA & Smoothing Mechanism
Ref 1: Exhibit 6, section 6.2.1.6 Accelerated CCA, p.18~20
Ref 2: Attachment17_CCA by Class_04162025
Ref 3: Attachment8_2026 PILs Workform_20250416
Ref 4: Chapter2Appendices_2BA_ Fixed Asset Cont_04162025

Preamble:

Per Ref 2, 3 & 4, OEB staff has compared capital additions, UCC schedule and CCA amounts (before CWIP addition and excluding land) across the three references and noted the difference of 2024 and 2025 in the Table (A) below.

Table (A): Capital Additions, UCC & CCA Difference

	Capital Additions		**UCC**		**CCA Amount**	
	2024	2025	2024	2025	2024	2025
CCA Workform (Ref 2) - A	14,960,011	12,853,401	116,197,744	119,433,046	9,568,944	9,618,099
PILs Workform (Ref 3) - B	n/a	13,302,572	116,197,743	119,846,282	9,568,946	9,654,033
Appendix-2BA (Ref 4) - C	15,750,887	18,502,819	n/a	n/a	n/a	n/a
Variance (B-A)	**n/a**	**449,171**	**0**	**413,236**	**0**	**35,934**
Variance (C-A)	**790,876**	**5,649,418**	**n/a**	**n/a**	**n/a**	**n/a**

Per Ref 2, OEB staff has complied the following Table (B) showing the difference of “Relevant factor” used to calculate the CCA amount between CCA Worksheet provided by Burlington Hydro and the staff calculation.

Table (B): Relevant factor Difference

Source	Class	2024 Prior COS PILs	2025 Prior COS PILs	2024 Current COS PILs	2025 Current COS PILs
Ref 2	12	0	0	0	0
Staff calculation	12	2	2	2	2
Variance		**2**	**2**	**2**	**2**
Ref 2	14.1	n/a	3	n/a	2
Staff calculation	14.1	n/a	7.8	n/a	6.8
Variance		**n/a**	**4.8**	**n/a**	**4.8**
Ref 2	43.2	0	0	2	2
Staff calculation	43.2	4	4	3	3
Variance		**4**	**4**	**1**	**1**

In Ref 1, Burlington Hydro states that the 2021 OEB approved rates incorporated the full benefit of the AIIP and there was no smoothing mechanism applied over its five-year IRM term. Burlington Hydro agreed to continue the use of Account 1592 to record the full revenue requirement of the phasing out period of the AIIP in 2024 and 2025, of which the amount proposed for disposition in this application was recorded in Account 1592.

In Ref 3, the PILs model shows that Burlington Hydro applies AIIP Phase Out effect for the bridge year 2025 CCA and the test year 2026 CCA.

Question(s):

a) Please confirm that the AIIP has been claimed in Burlington Hydro's tax filings for the period from 2021 to 2024.
b) Please reconcile and explain the variance identified in Table (A) and Table (B) above and update the relevant forms as applicable.

c) Please propose a smoothing mechanism by completing the following table complied by OEB staff to increase the PILs in the test year that is generated from the current PILs model.

	Burlington Hydro's Proposal regarding AIIP (applying AIIP from 2025 and forward years)
2026 PILs expense (a)	$ 931,830
Impact on PILs from the smoothing mechanism (b)	
Total Revenue Requirement Impact (c=a+b)	

Response:

a) BHI confirms that AIIP has been claimed in Burlington Hydro's 2021 to 2024 tax filings.

b) **Response for Table [A]**

BHI has made updates to the CCA Workform, the PILS Workform, and Appendix 2-BA to its Application as identified in its response to 1-Staff-1. The updated differences are provided in Table 1 below.

Table 1

Table (A): Capital Additions, UCC & CCA Difference

	Capital Additions		UCC		CCA Amount	
	2024	**2025**	**2024**	**2025**	**2024**	**2025**
CCA Workform (Ref 2) – A	14,955,263	12,652,974	115,423,084	118,304,895	9,564,197	9,630,462
PILs Workform (Ref 3) – B	14,955,263	12,652,974[1]	115,423,084[2]	118,304,895[3]	9,654,197	9,630,462
Appendix-2BA (Ref 4) – C	15,750,887	17,700,646	N/A	N/A	N/A	N/A
Variance (B-A)	**Nil**	**Nil**	**Nil**	**Nil**	**Nil**	**Nil**
Variance (C-A)	**795,624 [1]**	**5,047,672 [2]**	**N/A**	**N/A**	**N/A**	**N/A**

There are variances in the capital additions between the CCA Workform and Appendix 2-BA due to differences in the accounting and tax treatments. The reasons for these differences for 2024 and 2025 are identified below:

[1] Excludes CWIP addition of $203,215
[2] Excludes CWIP of $774,659
[3] Excludes CWIP balance of $977,874

[1] The difference of $795,624 for 2024 is explained as follows:

$755,928 Overhead charges capitalized in Appendix 2-BA are deducted as a
current period expense for tax in the PILS Workform;

$ 4,748 SR&ED amounts capitalized in Appendix 2-BA are deducted as SR&ED expenses in the year for tax purposes in the PILS Workform;
and

$ 34,948 Capital leases are treated as operating leases for tax purposes and therefore are not included as additions for tax in the PILS Workform.

[2] The difference of $5,047,672 for 2025 is explained as follows:

$ 289,483 Overhead charges capitalized in Appendix 2-BA are deducted as a current period expense for tax in the PILS Workform;

$ 136,546 SR&ED amounts capitalized in Appendix 2-BA are deducted as SR&ED expenses in the year for tax purposes in the PILS Workform;

$(140,700) The adjustment to Class 14.1 is shown in the adjustment column in the PILS Workform, versus the addition column in Appendix 2BA; and,

$4,762,343 This was an adjustment in Appendix 2-BA to move ICM additions to the 2026 Test year for the Dundas Road Widening Project. This adjustment is identified in the ICM column in Appendix-2BA. The PILS Workform reflects this adjustment as a decrease in the additions to the 2025 Bridge year.

Response for Table (B)

The updates to the PILS model and AIIP calculations are described in BHI's response to 9-Intervenor-148, 6-Staff-74 and 6-Staff-75. The appropriate relevant factors were used for both 2024 and 2025.

c) BHI provides Table 2 below to identify the impact of proposing a smoothing mechanism for the treatment of AIIP. The "2026 PILS expense (a)" in the table below is based on the updated PILs model as identified in BHI's response to 1-Staff-1. The table demonstrates an increase of $88,252 to the Total Revenue Requirement with respect to AIIP from 2025 and forward years. As identified in BHI's response to 9-Intervenor-148 (b), the updated AIIP requested for disposition is $441,261. The calculation below smooths this balance over the next 5 years.

Table 2

Description	Burlington Hydro's Proposal regarding AIIP (applying AIIP from 2025 and forward years)
2026 PILs expense (a)	$925,602
Impact on PILs from the smoothing mechanism (b)	88,252
Total Revenue Requirement Impact (c=a+b)	$1,013,854

6-Staff-79

Reference:
Error checking
Ref 1: Exhibit 6, section 6.2.1.6 p.19, row 24

Question(s):

a) Please confirm the five-year IRM term of its 2021 Cost of Service application is from 2021 to 2025.

Response:

a) BHI confirms the five-year IRM term of its 2021 Cost of Service application is from 2021 to 2025.

7-Staff-80

Reference:
Ref. 1: Exhibit 7, p. 11
Ref 2: EB-2020-0007, Cost Allocation Model Settlement

Question(s):

a) Please explain the reason for the material difference in the weighting factors for both Services and Billing and Collecting since Burlington Hydro's 2021 cost of service.

Response:

a) In preparing the response to this interrogatory, BHI identified that the Service weighting factors used in the cost allocation model were based on gross cost instead of installed cost (paid by BHI). BHI has corrected the Cost Allocation Model filed in response to these interrogatories to use installed cost to determine its service weighting factors. The updated model is filed as Attachment_2026 Cost Allocation Model_v1.0_BHI_07242025.

BHI provides the revised Services weighting factors compared to its 2021 weighting factors in Table 1 below. The revised Services weighting factors are not materially different compared to the 2021 weighting factors.

Table 1

Rate Class	Service Weighting Factor	
	2021	2026
Residential	1.00	1.00
GS<50 kW	0.50	0.45
GS>50 kW	0.00	0.00
Street Lights	0.09	0.05
Unmetered Scattered Load	0.96	0.49

BHI provides the 2026 Billing and Collecting weighting factors compared to its 2021 weighting factors in Table 2 below. The 2026 Billing and Collecting weighting factor for the GS>50 kW rate class has decreased due to a reduction in the amount of bad debt attributed to this rate class as a percentage of overall bad debt.

Table 2

Rate Class	Billing and Collecting Weighting Factor	
	2021	2026
Residential	1.00	1.00
GS<50 kW	1.58	1.59
GS>50 kW	10.30	4.79
Street Lights	0.61	0.89
Unmetered Scattered Load	0.83	0.91

8-Staff-81

Reference:
Ref. 1: Exhibit 8, p. 9
Ref.2: RTSR Workform, Tab 4

Question(s):

a) Please confirm which historic year of RRR data has been used in the RTSR form.
b) Please confirm which year of wholesale purchase volumes have been used
c) Please update UTR and Hydro One sub transmission rates for 2025/2026 in accordance with EB-2024-0032 (December 19, 2024).

Response:

a) BHI confirms that it has used 2024 RRR data in the RTSR form.

b) BHI confirms that it has used 2024 wholesale purchase volumes in the RTSR form.

c) BHI has updated the UTR and Hydro One sub transmission rates for 2025 in accordance with the OEB's rate orders EB-2024-0244 and EB-2024-0032 respectively. For 2026, BHI has used the same rates as 2025 as 2026 rates are not yet available. BHI provides an updated RTSR form as Attachment_OEB_RTSR_Workform_BHI_07242025.

   The updated RTSR model also includes a new EV Charging (EVC) rate for electric vehicle (EV) charging stations.

9-Staff-82

Reference:
DVA disposition
Ref 1: Exhibit 9, Section 9.1.0.1 & 9.1.0.2
Ref 2: Burlington Hydro's 2024 IRM Decision and Rate Order (EB-2023-0008)
Ref 3: Burlington Hydro's 2025 IRM Decision and Rate Order (EB-2024-0010)

Preamble:

Per Ref 2, OEB staff notes the Group 1 DVA balances were last disposed on a final basis in 2024 IRM application excluding Accounts 1588 and 1589.

Question(s):

a) Please confirm that Burlington Hydro is not requesting final disposition of its 2024 Group 1 DVA balances, previously disposed on an interim basis in 2025 IRM per Ref 3, in this application.
b) Please provide the status of the CIS implementation process and the anticipated process finish date per Ref 1.
c) Please clarify whether Burlington Hydro has identified any material adjustments to Group 1 accounts due to the new process? If yes, please provide the details.
d) Please confirm that the disposition of Group 2 accounts is on a final basis in the application. If not confirmed, please explain why not.

Response:

a) BHI confirms it is not requesting final disposition of its 2024 Group 1 DVA balances.

b) BHI is currently still in the process of verifying the accuracy of the automated settlement calculations and is targeting completion by the end of 2025.

c) BHI has not identified any material adjustments to Group 1 accounts due to the new process up to this point but needs to complete the verification.

d) BHI confirms that the disposition of Group 2 accounts is on a final basis.

9-Staff-83

Reference:
Account 1595 Sub-account (2021) & (2022)
Ref 1: 2025 IRM Model_BHI_20250211 (EB-2024-0010), Tab 3
Ref 2: DVA Continuity Schedule_20250416, Tab 2-A

Preamble:

OEB staff notes that the 2023 transactions for Account 1595 sub-account (2021) and (2022) in 2025 IRM rate generator (Ref 1) are different from the numbers entered in the DVA continuity schedule in this application in Ref 2, resulting in the opening balance of both sub-accounts in 2024 different from the closing balance in 2023.

OEB staff has compiled a table per Ref 1 & 2 as below, showing the variances of principal and interest for both years.

Table (1): Variance of principal and interest for 2021 & 2022 of Account 1595

	1595 (2021) Principal	1595 (2021) Interest	1595 (2022) Principal	1595 (2022) Interest
2023 Transactions per 2024 IRM Rate Generator (Ref 1)	($628,857)	$9,260	($471,747)	$4,590
2023 Transactions per the DVA continuity schedule (Ref 2)	($544,599)	($74,997)	($375,287)	($91,870)
Variance	($84,258)	$84,257	($96,460)	$96,460

Question(s):

a) Please confirm the table above.

b) If confirmed, please provide an explanation for the variance identified in the table above and revise the schedule as applicable.

c) If not confirmed, please provide an explanation.

Response:

a) BHI confirms the numbers entered in Table (1) are as filed in BHI's 2025 IRM Model (ref 1) and its 2026 Cost of Service Application DVA continuity schedule (ref 2).

b) The allocation between principal and interest recorded in the 2026 COS DVA continuity schedule (Ref 2) is correct and reconciles back to BHI's RRR 2.1.7 Trial Balance Group 1 Accounts reporting of Account 1595, filed April 29, 2025.

   Tab 3 in the 2025 IRM Rate Generator model (Ref 1) contained the correct total ending balance but did not have the correct allocation between principal and interest.

c) n/a

9-Staff-84

Reference:
CAA Workform
Ref 1: Commodity Analysis Workform 2026_CAA_workform_20250416, Tab GA 2024, Note 4 & Note 5
Ref 2: 2025 GA Analysis Workform_BHI_20240815 filed in 2025 IRM application, Tab Principal Adjustment

Preamble:

Per Ref 1, OEB staff notes that Note 4 includes unbilled adjustments for the current month and previous month when calculating the price variance.

Per Ref 2, OEB staff notes that Burlington Hydro historically recorded principal adjustment for CT148 True-up for Account 1589 and CT1142/142 for Account 1588 in 2022

Question(s):

a) Please explain why there is no principal adjustment (Note 9) for both Account 1588 (Item 3a, 3b) and Account 1589 (Item 2a, 2b) after 2022 provided that Burlington Hydro is still using unbilled revenue for GA consumption.

b) Please explain why there is no principal adjustment for CT148 True-up for Account 1589 and CT1142/142 for Account 1588 after 2022.

Response:

a) BHI records its unbilled revenue in the respective year in the GL as well as the variance activity for both Account 1588 and Account 1589. There is no adjustment required.

b) The principal adjustment for Account 1589 and Account 1588 was the result of a correction completed in 2023 related to 2022. There is no such adjustment for 2024.

9-Staff-85

Reference:
Account 1592
Ref 1: Exhibit 9, section 9.1.5.1 Impact to Account 1592 in 2021 and 2026
Ref 2: Attachment8_2026 PILs Workform_20250416, B1 Sch 1 Taxable Income Bridge
Ref 3: DVA Continuity Schedule_20250416, Tab 2-B

Question(s):

a) Please provide a copy of Schedule 8 in 2024 tax return when it is available and reconcile that with the accelerated CCA amount in PILs model.
b) In the DVA Continuity Schedule, it appears that the balance for Account 1592, Sub-account CCA Changes has been input into the control Account 1592 line instead of the CCA Changes sub-account line. Please confirm if this is the case and update the evidence accordingly. If not, please explain.
c) Please confirm Burlington Hydro will keep Account 1592 sub-account CCA changes open in case of any further CCA rules changes.

Response:

a) BHI provides a copy of Schedule 8 in the 2024 tax return as Appendix 9-Staff-85a). BHI provides an updated PILs model as Attachment_2026_PILS_Workform_BHI_07242025. The CCA in the PILs model identified in Tab “H1 Ch1 Taxable Income Hist” reconciles to Schedule 8 and is equal to $9,564,198.

b) BHI confirms that the balance for Account 1592, Sub-account CCA Changes was input into the control Account 1592 line instead of the CCA Changes sub-account line in the Application filed April 16, 2025. BHI updates the evidence accordingly and provides an updated DVA Continuity Schedule as Attachment_DVA_Continuity_Schedule_BHI_07242025.

c) BHI confirms that BHI will keep Account 1592 sub-account CCA changes open in case of any further CCA rules changes.

9-Staff-86

Reference:
Pole Attachment Revenue Variance
Ref 1: Exhibit 9, section 9.0.1, Table 1
Ref 2: Exhibit 9, section 9.1.7 Account 1508, Sub-account Pole Attachment Revenue Variance, Table 24, p. 39

Question(s):

a) Please explain why Burlington Hydro proposed to continue using the Pole Attachment account since Table 24 has already included the revenue forecast for the period up to December 2025.
b) Please update the evidence as applicable.

Response:

a) BHI proposed to continue using the Pole Attachment account in case there were any changes to the pole attachment rate over the 2026-2030 period. BHI is not forecasting any entries to this account and as such withdraws its request to continue using this account.

b) No update to the evidence is required.

9-Staff-87

Reference:
Group 2 DVAs
Ref 1: DVA Continuity Schedule_20250416, Tab 2-B

Preamble:

OEB staff notes that there is no activity recorded in the following Group 2 DVAs:

i) Account 1508 sub -account Retail Service Charge Incremental Revenue.
ii) Account 1508 sub -account Local Initiatives Program Costs
iii) Account 1508 sub -account Designated Broadband Project Impacts
iv) Account 1508 sub -account ULO Implementation Cost
v) Account 1508 sub -account LEAP EFA Funding Deferral Account

Question(s):

a) Please confirm Burlington Hydro proposes to discontinue using these accounts on a going forward basis and update the evidence as applicable.

Response:

a) BHI confirms it proposes to discontinue using these accounts on a going forward basis. No update to the evidence is required.

<u>9-Staff-88</u>

Reference:
Cloud DVA
Ref 1: EB-003-2023, Accounting Order, November 2, 2023
Ref 2: Cloud Computing Implementation Q&A Document, PDF, February 2024
Ref 3: EB-2024-0063, Notice, March 6, 2024
Ref 4: EB-2024-0063, Decision and Order, March 27, 2025
Ref 5: Exhibit 9, section 9.1.8 Disposition of Account 1511 Incremental Cloud Computing Implementation Costs

Question(s):

a) Please confirm whether Burlington Hydro has considered cloud computing solutions in its rebasing term and whether any amounts have been included in its forecast.
    i) If so, please explain where these amounts are included.
    ii) If not confirmed, please explain why not.

Response:

a) Yes, Burlington Hydro has considered cloud computing solutions in its rebasing term and amounts associated with these solutions have been included in its forecast.
    i) Table 1 and Table 2 below identify where these amounts have been included for OM&A and Capital respectively.

Table 1 – OM&A Amounts Related to Cloud Computing Solutions – 2026 Test Year

Category	Program	Sub-Program	2026
OM&A	Information Technology	Technology Managed Services	$22,500
		Software Licensing, Support and Maintenance	$250,027
		Hosting Services	$135,000
		Business Continuity & Disaster Recovery	$18,000
	Administration - Financial Reporting Management Tool	Consulting	$23,470
	Regulatory - Financial Reporting Management Tool	Consulting	$23,470
	Human Resources - Human Capital Management Tool	Payroll Software	$37,572
	Safety - Environmental, Helath and Safety Management Tool	HSEMS Technology Solution	$13,000
Total			**$523,038**

Table 2 – Capital Amounts Related to Cloud Computing Solutions – 2026 Test Year

Category	Description	2026
Capital	Inventory Management Controls	$51,000
	Accounting and Budgeting Software	$76,500
	Document Management	$48,960
	Identity and Access Management	$20,400
Total		**$196,860**

ii) n/a

9-Staff-89

Reference:
GOCA Variance Account
Ref 1: The OEB's Decision and Order for Getting Ontario Connected Act Variance Account, October 31, 2023

Question(s):

a) Please confirm that the OM&A cost in the test year reflect the Bill 93 impact for Burlington Hydro's locate cost.
   i) If so, please confirm that the Account 1508 sub-account GOCA variance account is to be discontinued after this rebasing application and update the evidence accordingly.
   ii) If not, please provide the rationale why the Bill 93 impact is not reflected in the test year's OM&A cost.

Response:

a) Please refer to BHI's response to 4-Intervenor-105 d) for an updated forecast of BHI's 2025 and 2026 locate costs. BHI does not confirm that the OM&A costs in the test year reflect the Bill 93 impact for BHI's locate costs. OM&A costs in the test year are based on BHI's existing (2024-2025) locate agreement, which was tendered in 2023 and may not reflect the full impact of Bill 93.

   i) BHI does not confirm that the Account 1508 sub-account GOCA variance account is to be discontinued after this rebasing application.

   ii) The Bill 93 impact is not reflected in the test year's OM&A cost because BHI has not tendered the 2026 locate services contract yet, and the full impact of Bill 93 may not have been fully reflected in the bids it received in response to its 2023 locate services RFP. In the event BHI incurs incremental locate costs arising from the implementation of Bill 93, it may require the use of Account 1508 sub-account GOCA variance account.

9-Staff-90

Reference:
Customer Choice Initiative Costs
Ref 1: Exhibit 9, section 9.1.9
Ref 2: Notice of Revised Proposal to Amend SSSC (August 25, 2020), p. 13
Ref 3: Accounting Order EB-2020-0152 (September 16, 2020)

Question(s):

a) Please provide the supporting calculation of the incremental operating expenses (annual costs) recorded in this account (Table 25 in Ref 1) and explain how these ongoing costs are related to the implementation and are directly attributable to the customer choice initiative.
b) Please confirm Burlington Hydro proposes to keep the Customer Choice Account open until its next rebasing application.
c) If b) is confirmed, please explain why it is needed to continue use this account provided that Table 25 in Ref 1 has already included the forecast amount up to December 2025.
d) If b) is not confirmed, please update the evidence accordingly.

Response:

a) The incremental operating costs recorded in Account 1508, Sub-account Customer Choice Initiative Costs are related to the implementation and directly attributable to the Customer Choice initiative because they represent the incremental temporary staff costs to process customer elections to switch from Time-of-Use (TOU) to tiered pricing (or vice versa). BHI also incurred direct costs for stationery and postage to mail confirmation letters to customers without an email address on file. BHI provides the supporting calculation of the incremental operating expenses recorded in this account (Table 25 in Ref 1) in Table 1 below.

Table 1

Period	2020 (Nov-Dec)	2021 (Jan-Feb)	2021 (Feb-May)	2021 (Jun-Dec)	2022 (Jan-Dec)	2023 (Jan-Dec)	2024 (Jan-Dec)
Resource Details	3 Staffing Temp Employees @ 100%	2 Staffing Temp Employees @ 100%	1 Staffing Temp Employee @ 100%	1 Staffing Temp Employee (part-time)	1 Staffing Temp Employee (part-time)	1 Staffing Temp Employee (part-time)	1 Staffing Temp Employee (part-time)
Incremental Staffing Costs	$ 27,017	$ 12,103	$ 22,214	$ 8,567	$ 14,109	$ 9,012	$ 7,698
Other Costs	$ 3,214		$0		$ -	$ -	$ -
Incremental Operating Expenses	**$ 30,231**		**$42,884**		**$ 14,109**	**$ 9,012**	**$ 7,698**

BHI's process for switching customers from TOU to tiered pricing was manual under its legacy CIS. Incremental operating costs decreased starting in 2022 as a portion of the process to switch customers from TOU to tiered pricing was automated in BHI's new

CIS, which was implemented in July 2021. However, BHI still incurs incremental operating costs to facilitate certain aspects of the switching process.

b) Confirmed, BHI proposes to keep the Customer Choice Account open until its next rebasing application.

c) BHI proposes to keep the Customer Choice Account open in case it incurs any incremental costs directly attributable to future code amendments made in response to Customer Choice initiatives.

d) Not applicable.

9-Staff-91

Reference:
Green Button Initiative
Ref 1: Account Order EB-2021-0183 (November 1, 2021)
Ref 2: Exhibit 9, section 9.1.10

Question(s):

a) Please provide the supporting calculation of the incremental operating expenses (annual costs) recorded in the Green Button Initiative account (Table 26 in Ref 2) and explain how these ongoing costs are related to the implementation and are directly attributable to the Green Button initiative.
b) Please confirm that Burlington Hydro proposes to discontinue the Green Button Account in this rebasing application.

Response:

a) The incremental operating costs are for monthly subscription, support and maintenance services for the Green Button Download My Data ("DMD") and Connect My Data ("CMD") Certified Platform in the Customer portal, as shown in Table 1 below.

Table 1

Incremental Operating Expenses	2024 Actual Year	2025 Bridge Year
Actual Monthly Cost	$6,685	$7,500
# of Months	12	12
Annual Cost	$80,225	$90,000

b) BHI confirms it proposes to discontinue the Green Button Account in this rebasing application.

9-Staff-92

Reference:
Collection Charge Lost Revenue
Ref 1: Exhibit 9, section 9.1.13, Table 32
Ref 2: BHI_IRR_Staff_20210201, 9-Staff-77, Table 17

Preamble:

In Ref 2, Burlington Hydro states the full year savings are $44,800.

Per Ref 1 & 2, OEB staff has complied the table below to compare the savings from process changes:

	Jul 2019~Dec 2019	Jan 2020~Dec 2020	Jan 2021~Apr 2021
# of Collection Notices issued	9,925	22,067	8,315
Savings from Process Changes	($22,400)	($31,482)	($11,558)

Question(s):

a) Please explain why the savings from process changes didn't change in proportion to the number of collection notices issued and the length of time.
b) Please provide the calculation of the savings from process changes for both 2020 and 2021.

Response:

a) The savings from process changes from Jul-Dec 2019 per Reference 2 reflected a full year of savings (in error) and should have been $11,200 instead of $22,400. This resulted in a net benefit to ratepayers as BHI offset the costs recorded in this account by higher savings than it achieved in 2019. The savings from process changes from Jan-Dec of 2020 ($1.43 per notice) and from Jan-Apr of 2021 ($1.39) are in proportion to the number of collection notices issued.

b) BHI provides the calculation of savings in Table 1 below.

Table 1

	Jan.2020 to Dec.2020	Jan.2021 to Apr.2021
# of Collection Notices	22,067	8,315
Cost to Mail Notices	$24,008	$8,814
Cost for Hand Delivery of Notices	$55,490	$20,372
Savings from Process Change	($31,482)	($11,558)
Savings from Process Change (per unit)	$1.43	$1.39

9-Staff-93

Reference:
Impacts Arising from the COVID-19 Emergency
Ref 1: Exhibit 9, section 9.1.6
Ref 2: Chapter 2 Filing Requirements (April 18, 2022), section 2.9.1.6
Ref 3: Covid-19 Report, June 17, 2021, Appendix B, section 4.4 & section 4.3.2
Ref 4: Burlington Hydro 2021 Scorecard
Ref 5: Burlington Hydro 2023 Scorecard

Preamble:

In Ref 3, Appendix B details on how to calculate the means tests, recovery limitations, and sequencing of the calculations. Section 4.4 discussed the Measuring Incremental Impacts. Section 4.3.2 specifies the details of Causation, Prudence, and Materiality Criteria.
Per Ref 4 & 5, OEB staff notes the 2021 achieved ROE is different from Ref 4 (5.84%) to Ref 5 (6.06%)

Per Ref 1 & 5, OEB staff has complied the following Table (A) showing the Means Test calculation:

Item		2020	2021 (Jan~Apr)	2021 (May~Dec)
OEB approved ROE % (Ref 1)	a	9.36%	9.36%	8.34%
Less: 300bps (Ref 1)	b	3.00%	3.00%	3.00%
Allowed ROE % (Ref 1)	c	6.36%	6.36%	5.34%
Regulated Deemed Equity $ (Ref 1)	d	$62,948,694	$58,755,052	$58,755,052
Allowed ROE $ (pro-rate to month)	c*d	$4,003,537	$1,245,607	$2,091,680
Achieved ROE $ (Ref 1)		$834,869	$2,649,765	$4,335,372
Means Tests		Pass	Fail	Fail

OEB Staff notes that the Means Tests for entire 2021 failed based on the actual ROE achieved in the respective period per Table (A) above.

Question(s):

Section A:

a) Please confirm OEB staff's observation in Table (A) or revise the table as applicable.
b) If confirmed, please update the Account 1509 balance by excluding the 2021 amount.

Section B:

a) Please provide breakdown of the annual amounts recorded in each of the Covid-19 sub-accounts, including the methodology used to measure incremental costs and savings.
   i) Please provide a breakdown of the amounts recorded in the account for which a 50% recovery rate applies.
   ii) Please provide a breakdown of the amounts recorded in the account (Exceptional Pool) for which a 100% recovery rate applies.
   iii) Please demonstrate that the impact recorded in the account have only been incurred as a result of the pandemic.
b) For the Prudence, please provide the breakdown of costs incurred related to Pandemic Planning Committee plan including the timing (months) of any expenditure.
c) For the Materiality, please fill in the following Table (B) compiled by OEB staff:

Item	2020	2021
Annual total cost		
Minus: Cost savings		
Minus: Amount recorded in Exceptional Pool		
Total		

   i) Please reconcile the amount provided in Table (B) to a) & b) of Section B above
   ii) Please reperform the materiality test separately based on: (1) the amount excluding exceptional pool; (2) exceptional pool amount
d) For the ROE calculated in Table 22 of Ref 1:
   i) Please confirm the achieved ROE amount is calculated after recording any amounts in the Covid-19 account.
   ii) Please explain why the 2021 achieved ROE is different in Ref 4 and Ref 5. Which amount is correct?
   iii) Please recalculate the achieved ROE amount by following each step outlined in Appendix B in Ref 3.
   iv) For achieved ROE amount calculated for 2020, please confirm it covered the entire 2020.
   v) If iv) is confirmed, please explain why the calculation covered is for the entire 2020 while the "PPC" is formed from March 2020 per Ref 1.
   vi) Please update the Table (A) after addressing the questions above and reconcile the amounts to a), b) & c) above in Section B.

Response:

Section A:

a) BHI is not able to confirm OEB's staff observation in Table A and provides a revised Table 1 below based on its interpretation of the means test framework. As part of this response, the achieved ROE amount has been revised to be calculated after recording any amounts in the Covid-19 account, in response to Section B part d i) of this interrogatory response.

Table 1

Description		2020	2021 (Jan-Apr Rates)	2021 (May-Dec Rates)
OEB approved ROE %	a	9.36%	9.36%	8.34%
Less: 300 bps	b	3%	3%	3%
Allowed ROE %	c	6.36%	6.36%	5.34%
Regulated Deemed Equity	d	$62,948,694	$58,755,052	$58,755,052
Achieved ROE Amount	e	$834,869	$2,649,765	$4,335,372
Amounts in Covid-19 account 50% recovery	f	$99,950	$38,261	$0
Achieved ROE %	(e+f)/d	1.49%	4.57%	7.38%
Means Tests		**Pass**	**Pass**	**Fail**

BHI respectfully disagrees with OEB staff's methodology used in Table A for the following reasons:

Means Test is ROE percentage-based, not dollar-based

As per the OEB's Covid-19 Report, June 17, 2021[1], Section 4.2.1, "the OEB will apply a means test to recoveries in the Account based on achieved ROE compared to a utility's OEB-approved ROE less 300 basis points." The test is explicitly a comparison of achieved ROE % to a threshold ROE %, not a dollar-based comparison of dollar earnings to allowed dollar return.

Deemed equity is considered fully in service throughout the year

For 2021 (Jan-Apr), OEB staff's calculation applies the allowed ROE % to the full-year deemed equity and then attributes it to partial periods (e.g., Jan–Apr) to derive an "

[1]EB-2020-0133: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency

Allowed ROE $ (pro-rate to month)". BHI submits that deemed equity represents a full-year investment base, not something that can be prorated linearly for shorter periods when calculating allowable earnings thresholds.

Achieved ROE calculation

As per the RRR 2.1.5.6 Filing Guide[2], "Achieved ROE is the regulated net income or loss as reported on the RRR 2.1.7 trial balance. Adjustments to regulated net income as per RRR 2.1.7 are made, as applicable, to determine adjusted regulated net income, which is divided by regulated deemed equity to determine achieved ROE %".

For interim or partial-year comparisons, BHI believes that it is more appropriate to use actual net income and adjustments for the period (e.g., Jan–Apr) and divide by the full-year deemed equity, to calculate the achieve ROE %, consistent with the way in which the OEB defines ROE % in these guidelines.

b) Not applicable.

Section B:

a)

i) BHI provides a breakdown of the amounts recorded in the COVID-19 sub-account "Other Costs and Savings" in Table 2 below. To satisfy part iii), BHI provides information in the "Comments" column to demonstrate that the impact recorded in the account was only incurred as a result of the pandemic. Further details on the incremental costs that BHI incurred directly as a result of the pandemic are discussed in Exhibit 1 of BHI's 2021 Cost of Service application.[3]

[2] RRR 2.1.5.6 ROE Complete Filing Guide issued March 2016
[3] EB-2020-0007, Exhibit 1, pp 42-44

Table 2

Description	2020	2021 (Jan-Apr)	Total	Calculation	Comments
Rental Vehicles and Fuel (Trades)	$83,250	$42,410	**$125,661**	Directly related to COVID-19	Additional vehicles (rentals) and fuel costs for trades staff during COVID-19 as each employee was required to drive a separate vehicle to maintain physical distancing. (refer to EB-2020-0007, Exhibit 1 at pages 43)
Mobile sites/ Off-sites	$113,050	$31,706	**$144,756**		Set-up of remote locations specifically in response to COVID-19 to segregate powerlines and stations crews. Costs included the rental of offsite trailers used as temporary camp offices, the rental of portable shower rooms, toilets, and sinks to support trade staff and additional contract labour to support remote location office operations. (refer to EB-2020-0007, Exhibit 1 at pages 43-44)
Safety / Cleaning Supplies	$49,700	$10,028	**$59,728**		Costs included safety supplies for staff, such as masks, PCR tests, and hand sanitizer, as well as enhanced nightly cleaning of buildings to mitigate the risk of COVID transmission. (refer to EB-2020-0007, Exhibit 1 at pages 42-43)
Computer Supplies, Apps, subscriptions	$20,167	$3,636	**$23,803**		Additional computer supplies (cameras, headsets etc.), COVID-19 screening app, additional zoom subscriptions to support social distancing and employees working from home (refer to EB-2020-0007 Exhibit 1 at pages 42-43)
Signage / Web portal	$8,315	$2,725	**$11,040**		Workspace upgrades with added Plexiglass, safety signage, and web portal (refer to EB-2020-0007 Exhibit 1 at page 42)
Total incremental costs	***$274,483***	***$90,504***	***$364,988***		
Insurance premiums	($27,540)	$0	**($27,540)**	Directly related to COVID-19	Savings in premium cost during COVID-19
Conferences, Seminars, Workshops	($25,428)	($13,983)	**($39,412)**	Savings are based the difference between the historcal average (2015-2019) and actual costs incurred	
Training	($21,616)	$0	**($21,616)**		
Total Savings	***($74,584)***	***($13,983)***	***($88,567)***		
Net Incremental costs before carrying charges	***$199,899***	***$76,521***	***$276,421***		
Carrying charges	$0	$0	**$44,018**	Based on OEB's prescribed rate	
Net Incremental costs after carrying charges	**$199,899**	**$76,521**	**$320,439**		

BHI previously included 100% of the amounts in the COVID-19 Account. However, it has now updated its DVA continuity schedule to reflect a 50% recovery rate of the amounts recorded in the Account, filed as Attachment_DVA_Continuity_Schedule_BHI_07242025.

ii) BHI has not recorded any amounts in the account (Exceptional Pool) for which a 100% recovery rate applies.

iii) All incremental costs and savings recorded in the COVID-19 sub-account “Other Costs and Savings” were incurred solely as a result of the COVID-19 pandemic and were not part of, or were incremental to, normal operating activities. Please refer to Table 2 above and to Exhibit 1 of BHI's 2021 Cost of Service application[4].

b) The incremental costs incurred related to the Pandemic Planning Committee plan are identified in BHI's response to part Section B a) i) above. Expenditures recorded to the Account were incurred from March to December of 2020 and from January to April of 2021.

c) BHI provides Table 3 below with information as requested in Table (B) compiled by OEB Staff.

Table 3

Item	2020	2021 (Jan-Apr)
Annual total cost	$274,483	$90,504
Minus: Cost savings	($74,584)	($13,983)
Minus:Amount recorded in Exceptional Pool	$0	$0
Total	**$199,899**	**$76,521**

i) The amounts provided in Table 3 above reconcile with the amounts provided in the row "Net Incremental costs before carrying charges" of Table 2 above.

ii) No amounts were recorded in the Account related to the exceptional pool, and as such the materiality test as provided in Exhibit 9 Section 9.1.6.4 is unchanged.

d)

i) The achieved ROE amount provided in Table 22 of Exhibit 9 of the Application at page 34 did include amounts in the COVID-19 account. Therefore, BHI has revised its achieved ROE % calculation after adding the COVID-19 amounts (50% recovery) and re-performed the means test. As identified in BHI's response to Section A part a) the means test is still passed.

ii) BHI filed a RRR revision in November 2022 that included changes to its ROE for 2021. The 2021 ROE in Ref 5 of 6.06% is correct. The changes were made to record 2021 approved LRAM recoveries, associated PILS impact and carrying charges.

[4] Ibid

iii) BHI provides the recalculation of the achieved ROE% in Table 4 below by following each step outlined in Appendix B[5].

Table 4

Description		2020	2021 Jan - Apr
OEB approved ROE %	a	9.36%	9.36%
Add: 300 bps	b	3%	3%
Allowed ROE (1st step)	c=a+b	12.36%	12.36%
Regulated Deemed Equity $	d	$62,948,694	$58,755,052
Achieved ROE Amount $	e	$834,869	$2,649,765
Amounts in Covid-19 account 50% recovery	f	$99,950	$38,261
Achieved ROE	(e+f)/d	1.49%	4.57%
Is Achieved ROE >= Allowed ROE (1st step)		No	No
Exceptional pool amounts	g	$0	$0
Achieved ROE with exceptional pool items	(e+f+g)/d	1.49%	4.57%
OEB approved ROE %	h	9.36%	9.36%
Less: 300 bps	i	-3%	-3%
Allowed ROE (2nd step)	j=h-i	6.36%	6.36%
Is Achieved ROE >= Allowed ROE (2nd step)		No	No
Non-Exceptional Pool items 50% recovery	k	$99,950	$38,261
Achieved ROE with non-exceptional pool items	(e+f+g+k)/d	1.64%	4.64%
Is Achieved ROE >= Allowed ROE (2nd step)		No	No

iv) BHI confirms that the achieved ROE amount calculated for 2020 covered the entire 2020.

v) BHI did not calculate an achieved ROE for 2020 based on net income for only the period from March to December. However, BHI believes that the achieved ROE based on net income for 10-months would not produce any different result for the means tests in Section A part a) and Achieved ROE with non-exceptional pool items in Section B part d) iii) as the achieved ROE of 1.49% in 2020 is significantly lower than the allowed ROE minus 300 basis points of 6.36%.

vi) BHI's response to Section A part a) includes an updated version of OEB's staff Table (A) reflecting all questions in this interrogatory, and it reconciles to parts a), b) & c) of Section B.

[5] EB-2020-0133: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency

9-Staff-94

Reference:
Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account (CVA1)
Ref 1: Exhibit 9, section 9.1.11
Ref 2: (EB-2020-0007) Decision and Rate Order, April 15, 2021, Accounting Order #1
Ref 3: (EB-2020-0007) BHI_Settlement Proposal_03172021, pg.12
Ref 4: (EB-2024-0010) BHI_questions Responses_OEBstaff_VECC_202401018, VECC-4

Preamble:

In Ref 1, Burlington Hydro states the 2021 Dundas Road Widening Project ("The Project") includes two scopes of work which is "Walkers Line to Appleby Line" and "Appleby line to Tremaine". The net capital budget of these two parts is $3,035,948 and is tracked in CVA1.

In Ref 2 & 3, the CVA1 established in Accounting Order #1 is to record the revenue requirement associated with the difference between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the Dundas Street Road Widening Project and the resulting impact during the IRM period. The Project is driven by a third-party and there is an inherent level of uncertainty with respect to the scope and whether it will be completed in the 2021 test year.

In Ref 4, in response to VECC-4, Burlington Hydro states that the Project was not completed in 2021 or subsequent years because it was delayed by the road authority. It further states that Burlington Hydro first became aware of the Appleby Line to Tremaine project in 2021 which was nondiscretionary per BHI's statutory obligations under the Public Service Works on Highways Act ("PSWHA").

OEB staff notes the CVA1 created associated with the original budget in Burlington Hydro's 2021 COS is to track the Project as a whole and the entire scope of the Project was not completed in 2021.

Question(s):

a) Please provide evidence showing "Appleby line to Tremaine" was included in the DSP of 2021 COS.
b) Please outline the timeline on a month basis of the Project:
    i) Which month/year did Burlington Hydro become aware of the cancellation of the Project?
    ii) Which month/year did Burlington Hydro add the capital addition of "Appleby line to Tremaine"?
c) Please elaborate how "Appleby line to Tremaine" is related to the Project and be tracked in CVA1.

Response:

a) BHI provides evidence that the "Appleby line to Tremaine" section of the 2021 Dundas Road Widening Project was included in BHI's 2021 DSP in Figure 1 below. In late 2020, this section of the Project was shifted from 2020 to 2021 due to scope changes by the road authority and a consequent delay in Project approval by the road authority. This increased the capital expenditures for the 2021 Dundas Road Widening Project from $2,526,183 (as filed on October 30, 2020) to $3,035,948 (as identified in BHI's interrogatory responses filed on February 1, 2021[1], and its response to a pre-settlement conference clarification question[2]). This change resulted in an increase of $509,765 as identified in Figure 1 below. $3,035,948 represents the amount tracked through CVA1.

Figure 1

Burlington Hydro Inc.
Pre-Settlement Conference Clarification Questions
Ontario Energy Board Staff
EB-2020-0007
Page 1 of 2

2-Staff-83 *(CQ-2-Staff-83)*
Ref: 2-Staff-9, IR_Attachment_2-Staff-9a, IR_Attachment_2-Staff-9b

Question(s):

a) Please explain drivers for the updated expenditures for the following projects:

- $509.8k increase to the Dundas Street Road Widening project in 2021
- $220k increase to the Building program in 2020
- $176.3k increase to the Customer Information System (Replacement) program in 2020, and $215.9k increase to the Customer Information System (Replacement) program in 2021

b) Please explain drivers for the $1.9 million increase in forecasted expenditures on the Dundas Street Road Widening project from the Needs Assessment step to the Program Alternatives Evaluation step.

Response:

a) The drivers for the updated expenditures for the following projects are as follows:

- **$509.8k increase to the Dundas Street Road Widening project in 2021:** This project was shifted from 2020 to 2021 due to changes by the Region in project scope and a consequent delay in project approval; the increase of $510k in 2021 is partially offset by a decrease in 2020 resulting in a total expenditure increase of $225k over 2020-2021. The net increase is primarily due to additional cost of overhead materials and labour as a result of changes in project scope.

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[1] EB-2020-0007, 2-Staff-9 a)
[2] EB-2020-0007, CQ-2-Staff-83

b) BHI provides the requested timelines as follows

   i. The staff responsible for this Project is no longer with BHI and as such BHI is unable to confirm the month/year it became aware of the deferral of the Project. However, records confirm that BHI's updated capital expenditure forecast from May 2021 reflect the "Walkers Line to Appleby Line" section of this Project being deferred beyond 2021.

   ii. The "Appleby line to Tremaine" section of this Project was added to BHI's capital additions in Q2 2021.

c) "Appleby line to Tremaine" is related to the Project because it is a subset of the Project to relocate BHI assets to accommodate the widening of Dundas Street. It is adjacent to the "Walkers Line to Appleby Line" section, as shown in Figure 2 below. The section highlighted in green is "Appleby Line to Tremaine" and the section highlighted in blue is "Walkers Line to Appleby Line". Both sections are mandatory System Access expenditures in accordance with BHI's statutory obligations under the Public Service Work on Highway Act ("PSWHA").

   "Appleby line to Tremaine" should be tracked in CVA1 because it was included in the $3,035,948 budget approved by the OEB, which represents the amount against which actual expenditures are to be compared.

Figure 2


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Sutton Dr
Zebra Robotics
Palladium Wy
Alexander's
Public School
Recently viewed
ORCHARD
The Brick Mattress Store
Pathfinder Dr
Thomas Alton Blvd
Millcroft Park Dr
Dryden Ave
Blue Spruce Ave
Canadian Tire
Activate Burlington
Millcroft Golf Club
Walkers Line
Upper Middle Rd

<u>9-Staff-95</u>

Reference:
Error checking
Ref 1: Exhibit 9, section 9.1.0.1 p. 22, row 14
Ref 2: Exhibit 9, section 9.1.0.1, p. 25, row 7
Ref 3: Exhibit 9, section 9.1.0.1, p. 25, Table 15
Ref 4: Exhibit 9, section 9.1.5.1, p. 31, row 15

Preamble:

In Ref 1, Burlington Hydro states Group 1 rate rider starts from Jan 1 until Dec 31, 2025. OEB staff notes it should be from Jan 1 until Dec 31, 2026.

In Ref 2, Burlington Hydro states Group 2 rate rider starts from Jan 1 until Dec 31, 2025. OEB staff notes it should be from Jan 1 until Dec 31, 2026.

In Ref 3, the title of the Table 15 shows Group 1 Disposition by Category. OEB staff notes it should be Group 2 Disposition by Category.

In Ref 4, Burlington Hydro states its five-year IRM term of 2021 Cost of Service application is from 2021 to 2026. OEB staff notes the five-year IRM term of its 2021 Cost of Service application is from 2021 to 2025.

Question(s):

a) Please confirm OEB staff's observations above and update the evidence as applicable.

Response:

a) BHI confirms OEB staff's observations above and confirms the dates in Attachment13_Tariff_Schedule_and_Bill_Impact_Model_BHI_04162025 were accurate.

   There are no updates to the evidence required as a result of the observations.

Appendix – 1-Staff-1

IR #	Update requested or identified in the response	Category	Updated Appendices/ Workforms/Schedules	Update Models	Impact to Rev Req Y(/N)
2-Staff-19 b	Update timing of Dundas Street Road Widening Project (Northampton Blvd to Guelph Line)	Fixed Assets /Rate Base	OEB Appendices 2-AA, 2-BA	RRWF,CA, PILS, Bill Impacts	Y
2-Staff-25 a	Update to miscellaneous capital projects 2025 and 2026	Fixed Assets /Rate Base	OEB Appendices 2-AA, 2-BA	RRWF,CA, PILS, Bill Impacts	Y
2-Staff-28 b	Update depreciation rate for UsoA 1611 in 2-BB Service Life	Fixed Assets /Rate Base	OEB Appendix 2-BB	N/A	N
2-Staff-29 a	Update fully depreciated amounts in 2025 and 2026 for Account 1920	Fixed Assets /Rate Base	OEB Appendix 2-C	RRWF,CA, PILS, Bill Impacts	N
2-Staff-30 a 2-Intervenor-21	Update accumulated depreciation amount for 2021 for Account 1609	Fixed Assets /Rate Base	OEB Appendix 2-BA	RRWF,CA, PILS, Bill Impacts	Y
3-Staff-32 a 3-Intervenor-81 c	Update load forecast model for the most recent historical months of 2025	Customer and Load Forecast	OEB Appendices 2-IB, 2-ZB	Load Forecast Model, RRWF,CA, PILS, Bill Impacts	Y
3-Staff-37	Update for IESO's revised 2025-27 eDSM savings forecast	Customer and Load Forecast	OEB Appendices 2-IB, 2-ZB	Load Forecast Model, RRWF,CA, PILS, Bill Impacts	Y
5-Staff-68 a	Revise Appendix 2-OA to show capitalization ratio of long-term debt	Cost of Capital	OEB Appendix 2-OA (with notional debt)	N/A	N
5-Staff-70 a 5-Intervenor-126	Update Appendix 2-OB to reflect new debt instruments	Cost of Capital	OEB Appendix 2-OB	RRWF,CA, PILS, Bill Impacts	Y
6-Staff-73 b	Update PILs to align with final 2024 Tax Return	PILS	n/a	RRWF, PILS, Bill Impacts	Y
6-Staff-75 a	Update PILs for 2024 actual SR&ED credits	PILS	n/a	RRWF, PILS, Bill Impacts	Y
7-Staff-80 a	Update Service Weighting Factors	Cost Allocation	n/a	CA, Bill Impacts	N
8-Staff-81 c	Update RTSR model for 2025 UTR and Hydro One sub transmission rates and new EV Charging rate for 2026	RTSRs	RTSR Workform, OEB Appendix 2-ZB	RRWF,CA, PILS, Bill Impacts	Y
9-Staff-93 Sec B a i) 9-Intervenor-149 b	Update the DVA Continuity Schedule to reflect a 50% recovery rate for Account 1509 (COVID-19)	DVAs	DVA Continuity Schedule	N/A	N
1-Intervenor-4 a 2-Intervenor-14 b 2-Intervenor-50 o ii) 2-Intervenor-52 a, b	Update 2025 and 2026 capital expenditures	Fixed Assets /Rate Base	OEB Appendices 2-AA, 2-AB, 2-BA	RRWF,CA, PILS, Bill Impacts	Y
2-Intervenor-15 a, b	Update Appendices to reflect updated capital expenditures for 2025 and 2026	Fixed Assets /Rate Base	OEB Appendices 2-AA, 2-AB, 2-BA	RRWF,CA, PILS, Bill Impacts	Y
2-Intervenor-19 a, b 2-Intervenor-65 a	Update Work in Progress for 2025 and 2026	Fixed Assets /Rate Base	OEB Appendices 2-BA	RRWF,CA, PILS, Bill Impacts	Y
2-Intervenor-26 a, b	Update Load forecast model for 2024 billing determinants	Customer and Load Forecast	OEB Appendices 2-IB, 2-ZB	Load Forecast Model, RRWF,CA, PILS, Bill Impacts	N
2-Intervenor-26 a, b	Reconcile billing determinants from ACM/ICM Model to Load Forecast Model	Fixed Assets /Rate Base	N/A	ICM/ACM Model	N
2-Intervenor-26 f	Update 2024 costs for OMS from $0.64M to $0.67M	Fixed Assets /Rate Base	OEB Appendix 2-AA, 2-AB, 2-BA	RRWF,CA, PILS, Bill Impacts	Y
3-Intervenor-87 d	Update for double counting of 1/2 year CDM adjustment	Customer and Load Forecast	N/A	Load Forecast Model	N
3-Intervenor-91 a	Correct error in CDM savings calculation	Customer and Load Forecast	N/A	Load Forecast Model	N
4-Intervenor-92	Increase in OEB costs of $14k and $71k in 2025 and 2026 respectively to reflect the OEB's 22% increase in costs in anticipation of increased expectations for the delivery of adjudicative and policy initiatives.[1]	OM&A	OEB Appendix 2-JA/2-JB/2-JC/2-L	RRWF,CA, PILS, Bill Impacts	Y
4-Intervenor-105 d	Increase to locate volumes for 2025 and 2026 and corresponding increase to locate costs $45k of $47k respectively	OM&A	OEB Appendix 2-JA/2-JB/2-JC/2-L	RRWF,CA, PILS, Bill Impacts	Y
4-Intervenor-116 a	Corrected 2024 FTE and headcount in OEB Appendix 2-K and Table 5 respectively	Headcount	OEB Appendix 2-K/2-L	N/A	N
4-Intervenor-124	Update 2021 Actual Incremental operating costs	OM&A	OEB Appendix 2-M	N/A	N
6-Intervenor-128 b	Update to Pole Attachment Charges	Other Revenue	OEB Appendix 2-H	RRWF,CA, PILS, Bill Impacts	Y
6-Intervenor-128 c	Update to Retail Service Charges	Other Revenue	OEB Appendix 2-H	RRWF,CA, PILS, Bill Impacts	Y
6-Intervenor-129 a	Update to Specific Service Charges	Other Revenue	OEB Appendix 2-H		Y
8-Intervenor-135	Update 2024 consumption to match RRR submission	Customer and Load Forecast	OEB Appendices 2-IB	Load Forecast Model	N
8-Intervenor-136	Update the formula for the calculation of the Supply Facilities Loss Factor	Supply Facilities Loss Factor	OEB Appendix 2-R	N/A	N
9-Intervenor-148 b	Update CCA Changes	DVAs	DVA Continuity Schedule; CCA by Class	N/A	N

[1] OEB Cost Assessment - Fiscal Year 2025-2026, June 30, 2025, p1

Appendix – 2-Staff-3c)

THIS AMENDING AGREEMENT made effective as of the last date on the signature page (the "**Effective Date**")

BETWEEN:

HYDRO ONE NETWORKS INC., a corporation incorporated pursuant to the laws of the Province of Ontario, (hereinafter referred to as "**Hydro One**") and licensed by the OEB.

OF THE FIRST PART;

- and -

BURLINGTON HYDRO INC. (hereinafter referred to as the "**Customer**")

OF THE SECOND PART.

From time to time, Hydro One and the Customer shall be individually referred to in this Agreement as "Party" and collectively as "Parties".

WHEREAS:

1. Hydro One and the Customer entered into a Connection and Cost Recovery Agreement dated March 30, 2011 (the "**Agreement**") in respect of the connection of the new Tremaine Transmission Station to Hydro One's transmission system; and

3. the parties intend to amend Schedules "A" and "B" of the Agreement in the manner set out herein to reflect the addition of the installation of feeder duct banks to the scope of the Work Chargeable to Customer.

NOW THEREFORE, in consideration of the foregoing, and of the mutual covenants, agreements, terms and conditions herein contained, the Parties, intending to be legally bound, hereby agree as follows:

1. Each of the parties represents and warrants that the recitals, to the extent that the recitals are applicable to that party, are true and accurate and form part of this Amending Agreement.

2. All terms which are defined in the Agreement and which appear in this Amending Agreement without definition, shall have the meanings respectively ascribed thereto in the Agreement.

3. The Agreement is hereby amended by:

(i) Deleting Section 2 of Part 5 of Schedule "A" and replacing it with the following:

2. Feeder Duct Banks

Hydro One will:

- Excavate a trench to the depth specified in Drawing #1 attached to this Agreement in as Schedule "C" ("**Drawing #1**") up to 1.2 m outside the station fence to avoid fence grounding.

CBR00191

- Install six (6) DB2 ducts and fill the trench with concrete as shown in Drawing #1 and Drawing #2 attached to this Agreement in as Schedule "C".
- Cap the ducts at both ends and back fill.

(ii) Deleting the Work Chargeable to Customer and the Manner Of Payment of the Estimate Of Capital Contributions and Work Chargeable To Customer set out in Schedule "B" and replacing it with the following:

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $550,457.00 comprised of:

For Revenue Metering Instrument Transformers: $485,457.00
For Feeder Duct Banks: $65,000.00

Actual Engineering and Construction Cost of the Work Chargeable to Customer: To be provided 180 days after Ready for Service Date.

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
April 15, 2011	$892,600.00	0	0	$50,457.00	$943,057.00
January 15, 2012	$2,750,000.00	0	0	$145,000.00	$2,895,000.00
October 15, 2012	$2,750,000.00	0	0	$210,000.00	$2,960,000.00
January 30, 2013	$2,750,000.00	0	0	$145,000.00	$2,895,000.00
Total	**$9,142,600.00**	**0**	**0**	**$550,457.00**	**$9,693,057.00**

(iii) Adding Appendix I to this Amending Agreement as Schedule "C" of the Agreement.

4. The parties do hereby reconfirm that the terms and conditions of the Agreement as amended by this Amending Agreement shall continue to be in full force and effect.

5. This Amending Agreement and each of the Parties' respective rights and obligations under this Amending Agreement, shall be binding on and shall inure to the benefit of the Parties hereto and each of their respective successors and permitted assigns.

6. This Amending Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

IN WITNESS WHEREOF, the Parties hereto, intending to be legally bound, have caused this Amending Agreement to be executed by the signatures of their proper officers duly authorized in their behalf.

HYDRO ONE NETWORKS INC.

Bradley Colden

Name: Brad Colden
Title: Manager – Customer Business Relations
Date: June 28, 2012
I have the authority to bind the Corporation

BURLINGTON HYDRO INC.

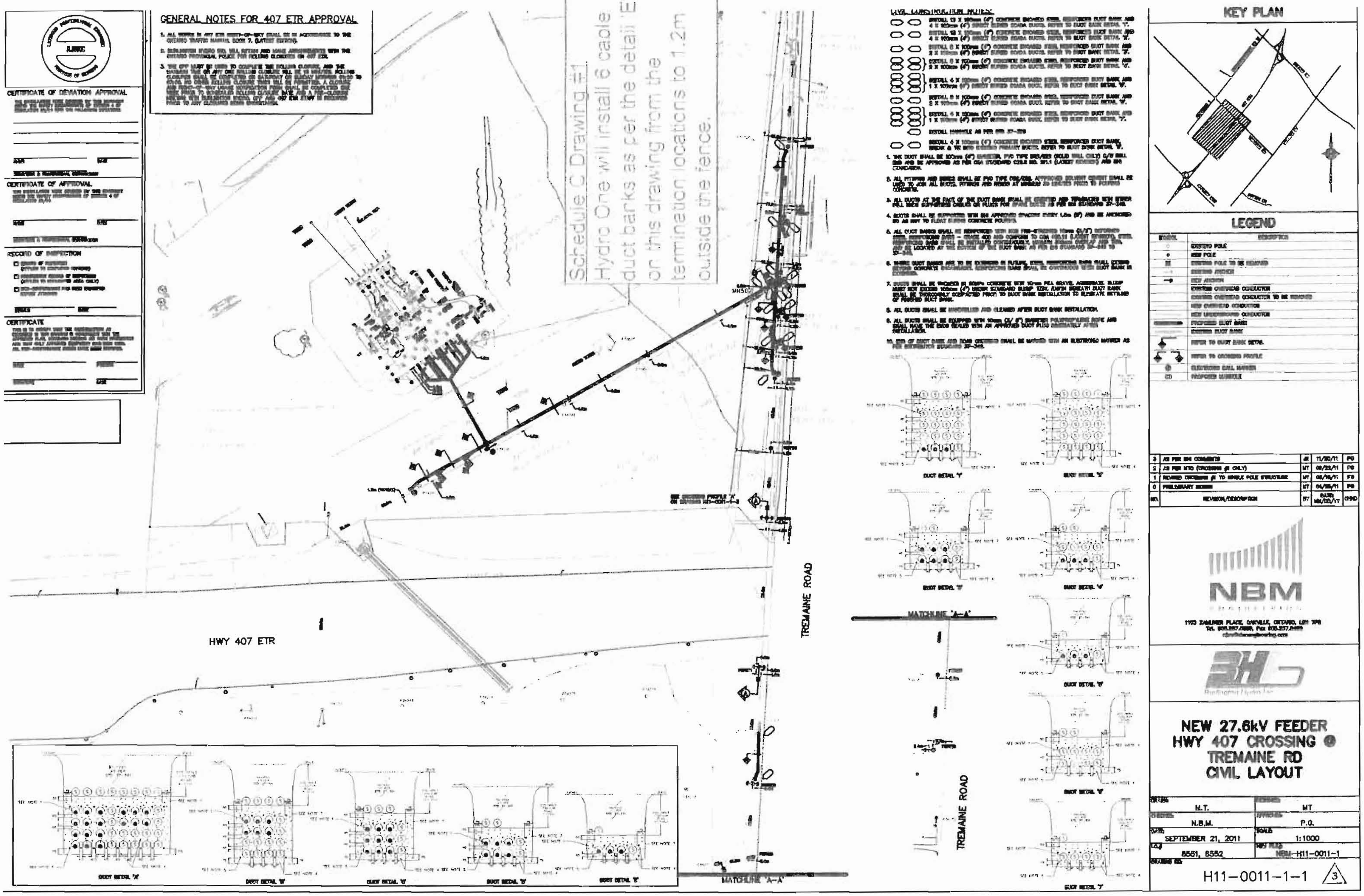
Name: Gerry Smallegange
Title: President & CEO
Date: June 21/12
I have the authority to bind the Corporation

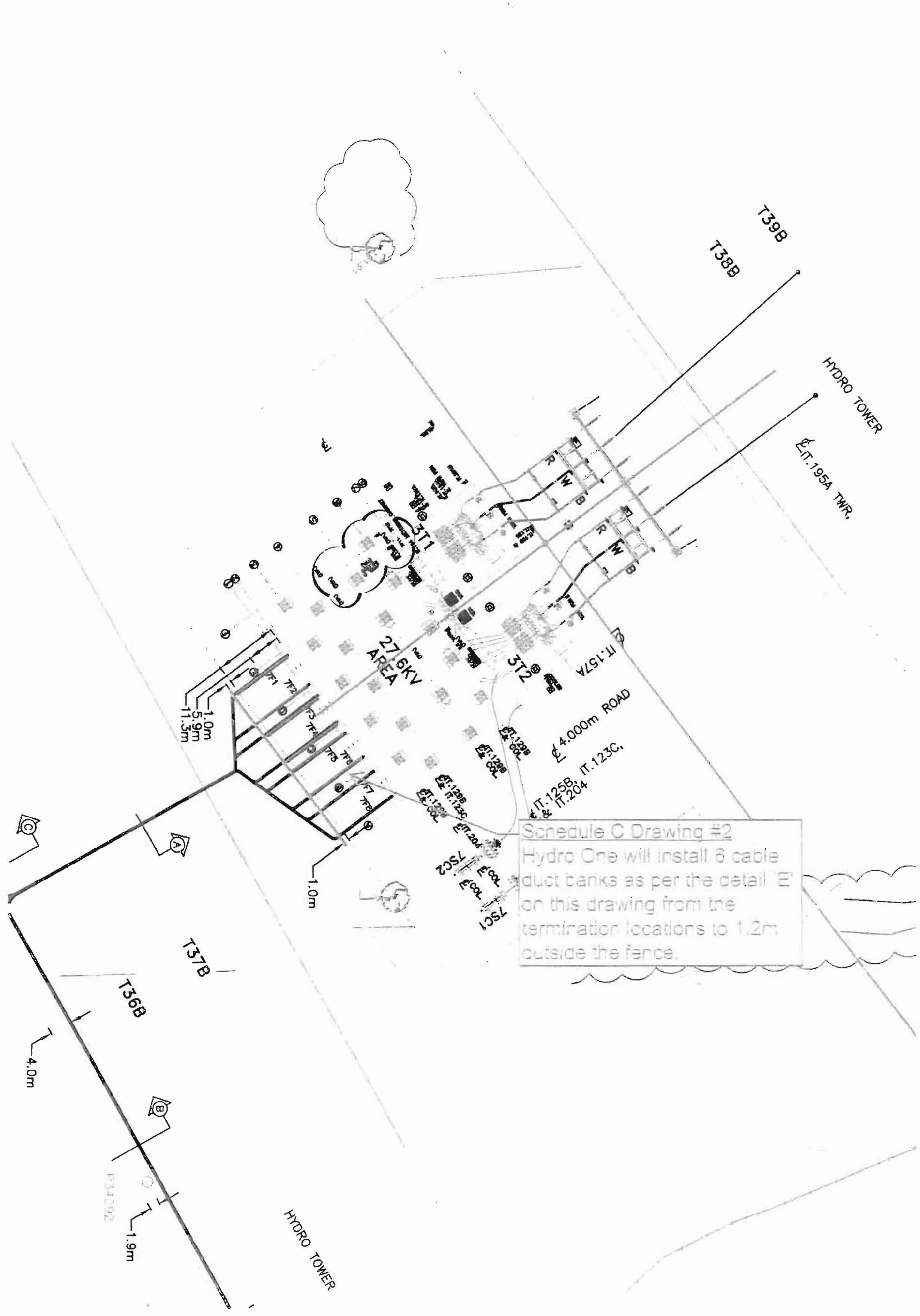
Appendix I to Amending Agreement:

Schedule "C": Drawing #1 and #2

Schedule C Drawing #1

Hydro One will install 6 cable duct banks as per the detail 'E' on this drawing from the termination locations to 1.2m outside the fence.





T39B
T38B
HYDRO TOWER
IT.195A TWR.
3T1
3T2
IT.157A
27.6KV AREA
4.000m ROAD
IT.125B, IT.123C, & IT.204
1.0m
5.9m
11.3m
1.0m
7SC2
7SC1
Schedule C Drawing #2
Hydro One will install 6 cable duct banks as per the detail 'E' on this drawing from the termination locations to 1.2m outside the fence.
T37B
T36B
4.0m
1.9m
HYDRO TOWER

Connection and Cost Recovery Agreement

between

Burlington Hydro Inc.

and

Hydro One Networks Inc.

for

Tremaine Transformer Station

Burlington Hydro Inc. (the "**Customer**") has requested and **Hydro One Networks Inc.** ("**Hydro One**") has agreed to build a new 230/27.6 kV, 75/100/125 MVA Transformer Station in the vicinity of Tremaine Road and Hwy 407 in the City of Burlington (the "**Project**") on the terms and conditions set forth in this Agreement dated March 30, 2011 (the "**Agreement**") and the attached Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects V3 9-2007 R5 (the "**Standard Terms and Conditions**" or "**T&C**"). Schedules "A" and "B" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

The Customer's load in North Burlington has exceeded the available capacity of Hydro One's transformation facilities, specifically, Palermo TS, which currently serves the Customer, Milton Hydro Distribution Inc. and Oakville Hydro Electricity Distribution Inc. The Customer has advised Hydro One that it will require new transformation capacity to supply existing capacity shortfall as well as its future load growth requirements. Hydro One will design and construct a 230/27.6 kV, 75/100/125 MVA transformer station, Tremaine TS, on the west side of Tremaine Road, north of Hwy 407 in the City of Burlington to supply the Customer and Milton Hydro Distribution Inc.

Term: The term of this Agreement will commence on the date that is the latter of the date that:

(a) this Agreement is fully executed by the Customer and Hydro One; and
(b) Milton Hydro Distribution Inc. executes and delivers the Connection and Cost Recovery Agreement to be made between Hydro One and Milton Hydro Distribution Inc. for the Project,

and will terminate on the 25^{th} anniversary of the In Service Date.

Special Circumstances:

The Customer acknowledges that the cost of the Project will be shared between the Customer and Milton Hydro Distribution Inc. Seventy-five percent (75%) of the capacity of Tremaine TS is to be allocated to the Customer, with the remainder allocated to Milton Hydro Distribution Inc. Costs are to be shared in accordance with the proportion of assigned capacity.

Hydro One acknowledges that the Customer bears no responsibility whatsoever for the portion of the costs payable by and revenues to be received from Milton Hydro Distribution Inc. in respect of the Project.

In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to:

(a) the Customer executing and delivering this Agreement to Hydro One by no later than **April 15, 2011;** and
(b) Milton Hydro Distribution Inc. executing and delivering the Connection and Cost Recovery Agreement to be made between Hydro One and Milton Hydro Distribution Inc. for the Project by no later than **April 15, 2011**.

Subject to Section 31, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Brad Colden
Manager - Customer Business Relations
I have the authority to bind the Corporation.

BURLINGTON HYDRO INC.

Gerry Smallegange
President & CEO
I have the authority to bind the Corporation.

MICHAEL KYSLEY
EVP & CFO

Schedule "A" (Tremaine TS)

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will design, construct, own and operate a new 75/125 MVA, 230/27.6 kV DESN, Tremaine TS, to be located at a new site located at Tremaine Road and just north of Highway 407 in the City of Burlington ("**Tremaine TS**").

Connection Point: 230 kV transmission circuits, T38B and T39B, approximately 4 kilometres west of Hydro One's Palermo TS.

Ready for Service Date: January 31, 2013

HYDRO ONE CONNECTION WORK

Part 1:Transformation Connection Pool Work

Hydro One will:
Design and build Tremaine TS as described below:

1. General Requirement

- Obtain approvals and permits as required for the stations facilities. These include, and are not necessarily limited to those related to noise, soil removals, drainage, and landscaping.
- Carry out acceptance checks, testing and commissioning of station equipment and associated systems.
- Provide perimeter chain-link fencing and access gate.
- Provide required site drainage.
- Provide required station access roads.
- Provide landscaping.

2. 230 kV Switchyard

- Provide and install two (2) 230 kV motorized disconnect switches to meet the requirements of the line tap and to interrupt the maximum transformer magnetizing current.
- Provide and install two (2) 75/100/125 MVA, 230/27.6-27.6 kV transformers as per CSA standards with a minimum summer 10 day LTR of 170 MVA.
- Provide and install transformer cooler and conservator tanks.
- Provide and install spill containment around the two transformers, as required by the Ministry of Environment.
- Provide and install six (6) phase-to-ground HV station class surge arresters, one for each phase of the HV bushings.
- Provide and install all required insulators, support structures, foundations and 230 kV cabling connecting the above equipment.

3. 27.6 kV Switching Facilities

The LV switchyard will be designed to allow for overhead egress of the eight (8) feeders (future twelve (12)). Scope of work includes the following:

- Provide and install twelve (12) LV station class surge arresters.
- Provide and install four (4) 1.5 ohm neutral reactors.
- Provide and install two (2) 27.6 kV main buses.
- Provide and install four (4) 2500 Ampere LV transformer breakers each with two (2) isolating switches.

- Provide and install one (1) normally open 2500 Ampere bus tie breaker with two (2) isolating switches.
- Provide and install eight (8) 1200 Ampere feeder breakers each with associated isolating switches. Six (6) feeder breakers will be for the Customer's use.
- Provide space for an additional four (4) feeder breakers and associated isolating switches.
- Provide and install bus work between the main buses and the feeder breakers.
- Provide and install four (4) three-phase feeder tie switches.
- Provide and install eight (8) protections sets of instrument transformers (potential and current transformers) for protection purposes.
- Provide and install eight (8) sets of feeder buses connecting the feeder breakers, the feeder tie switches and the Customer's feeders.
- Provide and install all required insulators, support structures, foundations and LV cabling connecting the above equipment.
- Provide space for two (2) future 27.6 kV capacitor banks and associated breakers.

4. AC and DC Station Service Systems

- Provide and install a complete AC Station Service System including two (2) pad-mounted Station Service Transformers with associated fusing, insulators, transfer switches, breakers, disconnect switches, panels and cabling.
- Provide a complete DC Station Service System as part of a pre-wired PCT building.

5. Protection, Control and Teleprotections Systems

- Provide and install a pre-fabricated & pre-wired PCT building.
- Review and revise, as required, the line protections on T38B and T39B.
- Review and advise the Customer as to any required changes to line protections on T38B and T39B.
- Provide SCADA communications to OGCC and IESO.
- Provide under-frequency load shedding relaying, as required.
- Witness P&C building manufacturer commissioning.
- Commission all P&C devices associated with the new facilities as well as at existing facilities connected to 230 kV circuits, T38B and T39B.
- Provide final single line diagram & confirm protection settings.

6. Grounding and Lightning Protection

- Provide and install station ground grid in the new switchyard.
- Provide grounding for the new sections of station fence.
- Provide standard grounding for the power transformers, HV and LV surge arresters, HV and LV switches, breakers and all steel structures.
- Provide perimeter grounding for the PCT building and connect to the grounding bus inside the PCT building.
- Provide lightning protection at the TS, as required.

7. Exclusions/Assumptions

Cost estimates are based on the following assumptions:

- Sound attenuation measures are not included in this scope of work as their need has yet to be verified.
- Soil conditions and resistivity at the site is good.
- Excavated soil is not contaminated.

8. Property Procurement

- Purchase property required for Tremaine TS.
- Obtain Environmental Assessment and all other permits/approvals associated with the or required for Tremaine TS or the 230 kV line connections.
- Permits and approvals associated with the distribution feeders are the responsibility of the Customer.

NOTES:

None.

Part 2: Line Connection Pool Work

Hydro One will:

- Provide 230 kV line taps from circuits T38B and T39B to the station line terminating structures.
- Provide 230 kV mid-span openers on the line taps.

NOTES:

None.

Part 3: Network Customer Allocated Work

Hydro One will:

- Revise, own and maintain tele-protections for circuits T38B and T39B as required to accommodate the New or Modified Connection Facility.
- Modify existing master SCADA at Hydro One's Ontario Grid Control Centre (OGCC) to provide control of the New or Modified Connection Facility

Part 4: Network Pool Work (Non-Recoverable from Customer)

Hydro One will:

Not Applicable.

Part 5: Work Chargeable to Customer

Hydro One will:

1. Revenue Metering Instrument Transformers

- Specify, supply, install and connect twelve (12) Revenue Canada approved revenue metering potential transformers (PTs) and twelve (12) free standing Revenue Canada approved revenue metering current transformers (CTs) on LV bus structures. The bus structure is to be modified to accommodate the installation.
- Provide four (4) metering junction boxes on the structure supporting the revenue metering CTs.
- Supply, install and terminate the secondary cables from the instrument transformer terminal boxes to metering junction boxes and to the metering cabinets provided by the Customer.
- Install and terminate 120 VAC Station Service cables from AC Station Service Distribution panel to the metering cabinets provided by the Customer.
- Install and terminate telephone service cables from telecom cable interface box to metering cabinets provided by the Customer.
- Install the structure supporting the Customer's metering cabinets to a location outside the PCT building.
- Providing spare instrument transformers are NOT included in the scope of work.

2. Feeder Duct Banks

- Provision by Hydro One of feeder duct banks within the station fence, if required, is NOT covered by this Agreement. If the Customer wishes to have Hydro install feeder duct banks, this work would be dealt with by a separate agreement.

NOTES:

None

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- requirement for Hydro One to obtain approval under Section 92 (leave to construct) of the *Ontario Energy Board Act* if the transmission line route selected by Hydro One is greater than 2 km in length;
- Hydro One having to expropriate property under the *Ontario Energy Board Act;*
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the *Ontario Energy Board Act* or any approval issued by the OEB to expropriate under the *Ontario Energy Board Act*; and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Transformation Connection Pool Work,;
(ii) the Line Connection Pool Work;
(iii) Network Pool Work
(iv) Network Customer Allocated Work; and
(v) the Work Chargeable to Customer.

At that point, no further Non-Customer initiated scope changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

The Customer will:

- Provide the revenue metering instrument transformers for installation by Hydro One. These must be dedicated instrument transformers which satisfy the latest IESO requirements.
- Provide and install revenue metering cabinets and associated metering equipment and cabling.
- Order a landline telephone service for IESO MV90 access and ensure that the service is available at least two weeks prior to in-service date.
- Accept responsibility for the registration of the revenue metering installations. The IESO registration work must be completed at least two weeks prior to the in-service date.
- Accept responsibility for purchasing and storing any spare equipment associated with the revenue metering installation (including instrument transformers).
- Provide and install 27.6 kV feeder conductors.
- Provide and install the drop leads to make connection to NEMA pads at feeder disconnect switches.
- Provide feeder protection settings for implementation by Hydro One.

The Customer will be responsible for the cost of feeder duct banks, if required, within the station fence.

EXISTING LOAD:

	A	**B**		
Existing Load Facility	**Existing Load (MW)[1,]**	**Normal Capacity (MW)[2]**		
Burlington TS	156.0	156.0		
Bronte TS (T2)	30.0	30.0		
Cumberland TS	148.2	148.2		
Palermo TS	30.7	30.7		
Total	364.9	364.9		

Notes:

1. Existing Load means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the *Transmission System Code).*
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the *Transmission System Code* and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.
3. "Normal Capacity" value shown is for the portion of the facility's capacity which is available for supplying the Customer.
4. Where the "Existing Load" has exceeded the "Normal Capacity", the "Existing Load" has been set equal to the "Normal Capacity".

<u>OTHER RELEVANT CONSIDERATIONS:</u> None

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR ODIFICATIONS:

None

MISCELLANEOUS

Customer Connection Risk Classification: Low Risk

True-Up Points: **If Low Risk** (a) following the fifth and tenth anniversaries of the In Service Date; and
(b) following the fifteenth anniversary of the In Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's HST Registration Number: 868291980RT

Documentation Required (after In Service Date): Feeder egress drawings

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work.

Approval Date (if Section 92 required to be obtained by Hydro One): Not required

Security Requirements: Nil

Security Date: Nil

Easement Required from Customer: No

Easement Date: Not applicable

Easement Lands: Not applicable

Easement Term: Not applicable

Approval Date (for OEB leave to construct): Not required

Revenue Metering: IESO compliant revenue metering to be provided by the Customer.

Customer Notice Info:

Burlington Hydro Inc.
P.O. Box 5018
1340 Brant Street
Burlington, Ontario
L7R 3Z7

Attention: Joe Saunders, Director, Regulatory Compliance and Asset Management
Fax #: 905-332-0684

Schedule "B" (Tremaine TS)

Costs of the Project are being apportioned between the Customer and Milton Hydro Distribution Inc. based on the Customer having 75% of the 153MW available capacity at Tremaine TS and Milton Hydro Distribution Inc. having 25%. As such, the Customer will be responsible for 75% of the total cost of the Project.

The Customer will have 114.75MW of contracted capacity at Tremaine TS.

The Customer will initially have six (6) feeder positions at Tremaine TS.

The assignment of overload credits at Palermo TS is based on the Customer's loads which exceed assigned capacity, as shown in Column "B" of the "Existing Load" Table.

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work:
Total Project Cost: $28,301,225.00
Cost Allocated to the Customer: $21,225,919.00

Estimate of Transformation Connection Pool Work Capital Contribution: $9,142,600.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Transformation Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: No

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work:
Total Project Cost: $1,267,806.00
Cost Allocated to the Customer: $950,855.00

Estimate of Line Connection Pool Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Line Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Line Connection Pool Work Capital Contribution: To be provided 180 days after Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: N/A

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work:

Total Project Cost: $431,442.00
Cost Allocated to the Customer: $323,582.00

Estimate of Network Customer Allocated Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Network Customer Allocated Work: To be provided 180 days after Ready for Service Date

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable from Customer) is $0. Subject to Sections 10.3 and 18 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer:
For Revenue Metering Instrument Transformers: $485,457.00

Actual Engineering and Construction Cost of the Work Chargeable to Customer: To be provided 180 days after Ready for Service Date.

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
April 15, 2011	$892,600	0	0	$50,457	$943,057
Jan 15, 2012	$2,750,000	0	0	$145,000	$2,895,000
Oct 15, 2012	$2,750,000	0	0	$145,000	$2,895,000
Jan 30, 2013	$2,750,000	0	0	$145,000	$2,895,000
Total	**$9,142,600**	**0**	**0**	**$485,457**	**$9,628,057**

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	32.9	32.9	32.9	698.9
2nd Anniversary of In Service Date	36.5	36.5	36.5	775.2
3rd Anniversary of In Service Date	40.2	40.2	40.2	852.9
4th Anniversary of In Service Date	43.8	43.8	43.8	929.3
5th Anniversary of In Service Date	47.4	47.4	47.4	1007.0
6th Anniversary of In Service Date	51.0	51.0	51.0	1083.2
7th Anniversary of In Service Date	54.6	54.6	54.6	1159.6
8th Anniversary of In Service Date	58.3	58.3	58.3	1237.3
9th Anniversary of In Service Date	61.8	61.8	61.8	1313.5
10th Anniversary of In Service Date	65.4	65.4	65.4	1389.6
11th Anniversary of In Service Date	68.9	68.9	68.9	1463.6
12th Anniversary of In Service Date	72.1	72.1	72.1	1530.9
13th Anniversary of In Service Date	74.9	74.9	74.9	1591.6
14th Anniversary of In Service Date	77.4	77.4	77.4	1644.0
15th Anniversary of In Service Date	79.5	79.5	79.5	1689.3
16th Anniversary of In Service Date	81.1	81.1	81.1	1721.9
17th Anniversary of In Service Date	82.3	82.3	82.3	1747.8
18th Anniversary of In Service Date	83.2	83.2	83.2	1767.4
19th Anniversary of In Service Date	84.0	84.0	84.0	1784.1
20th Anniversary of In Service Date	84.9	84.9	84.9	1802.2
21st Anniversary of In Service Date	85.6	85.6	85.6	1818.8
22nd Anniversary of In Service Date	86.4	86.4	86.4	1835.5
23rd Anniversary of In Service Date	87.3	87.3	87.3	1853.6
24th Anniversary of In Service Date	88.0	88.0	88.0	1870.2
25th Anniversary of In Service Date	88.8	88.8	88.8	1886.7

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	32.9	32.9	6.1	57.4
2nd Anniversary of In Service Date	36.5	36.5	6.7	63.6
3rd Anniversary of In Service Date	40.2	40.2	7.4	70.0
4th Anniversary of In Service Date	43.8	43.8	8.0	76.3
5th Anniversary of In Service Date	47.4	47.4	8.7	82.7
6th Anniversary of In Service Date	51.0	51.0	9.4	88.9
7th Anniversary of In Service Date	54.6	54.6	10.0	95.2
8th Anniversary of In Service Date	58.3	58.3	10.7	101.6
9th Anniversary of In Service Date	61.8	61.8	11.4	107.8
10th Anniversary of In Service Date	65.4	65.4	12.0	114.1
11th Anniversary of In Service Date	68.9	68.9	12.7	120.1
12th Anniversary of In Service Date	72.1	72.1	13.3	125.7
13th Anniversary of In Service Date	74.9	74.9	13.8	130.6
14th Anniversary of In Service Date	77.4	77.4	14.2	135.0
15th Anniversary of In Service Date	79.5	79.5	14.6	138.7
16th Anniversary of In Service Date	81.1	81.1	14.9	141.3
17th Anniversary of In Service Date	82.3	82.3	15.1	143.5
18th Anniversary of In Service Date	83.2	83.2	15.3	145.1
19th Anniversary of In Service Date	84.0	84.0	15.4	146.5
20th Anniversary of In Service Date	84.9	84.9	15.6	147.9
21st Anniversary of In Service Date	85.6	85.6	15.7	149.3
22nd Anniversary of In Service Date	86.4	86.4	15.9	150.7
23rd Anniversary of In Service Date	87.3	87.3	16.1	152.2
24th Anniversary of In Service Date	88.0	88.0	16.2	153.5
25th Anniversary of In Service Date	88.8	88.8	16.3	154.9

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	32.9	32.9	0.5	19.5
2nd Anniversary of In Service Date	36.5	36.5	0.6	21.7
3rd Anniversary of In Service Date	40.2	40.2	0.6	23.8
4th Anniversary of In Service Date	43.8	43.8	0.7	26.0
5th Anniversary of In Service Date	47.4	47.4	0.7	28.2
6th Anniversary of In Service Date	51.0	51.0	0.8	30.3
7th Anniversary of In Service Date	54.6	54.6	0.8	32.4
8th Anniversary of In Service Date	58.3	58.3	0.9	34.6
9th Anniversary of In Service Date	61.8	61.8	1.0	36.7
10th Anniversary of In Service Date	65.4	65.4	1.0	38.8
11th Anniversary of In Service Date	68.9	68.9	1.1	40.9
12th Anniversary of In Service Date	72.1	72.1	1.1	42.8
13th Anniversary of In Service Date	74.9	74.9	1.2	44.5
14th Anniversary of In Service Date	77.4	77.4	1.2	46.0
15th Anniversary of In Service Date	79.5	79.5	1.2	47.2
16th Anniversary of In Service Date	81.1	81.1	1.2	48.1
17th Anniversary of In Service Date	82.3	82.3	1.3	48.9
18th Anniversary of In Service Date	83.2	83.2	1.3	49.4
19th Anniversary of In Service Date	84.0	84.0	1.3	49.9
20th Anniversary of In Service Date	84.9	84.9	1.3	50.4
21st Anniversary of In Service Date	85.6	85.6	1.3	50.8
22nd Anniversary of In Service Date	86.4	86.4	1.3	51.3
23rd Anniversary of In Service Date	87.3	87.3	1.3	51.8
24th Anniversary of In Service Date	88.0	88.0	1.4	52.3
25th Anniversary of In Service Date	88.8	88.8	1.4	52.7

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

1. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;
(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;
(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
(f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The GST registration number for Hydro One is 87086-5821 RT0001 and the GST registration number for the Customer is as specified in Schedule "A" of the Agreement; and
(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, Connection and operation of the New or Modified Connection Facilities;

(b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(h) Hydro One is not permitted to Connect any new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the *Transmission System Code*, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable

Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Hydro One Connection Work described in Schedule "A", Hydro One shall: provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the *Transmission System Code*, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
(iv) participation in the commissioning, inspection or testing of the Customer's Facilities,

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work ;
(d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the *Transmission System Code*) or a Force Majeure Event;
(e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
(f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*, such leave is obtained on or before the date specified as the Approval Date in Schedule "A" of the Agreement;
(g) where applicable, Hydro One received the easement described in Section 24 hereof by the Easement Date specified in Schedule "A" of the Agreement;
(h) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Hydro One Connection Work:
   (i) environmental approvals, permits or certificates;
   (ii) land use permits from the Crown; and
   (iii) building permits and site plan approvals;
(j) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on terms substantially similar to the form of the easement that

is attached hereto as Appendix "B" of these Standard Terms and Conditions for the Project, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;

(k) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and

(l) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

6. Upon completion of the Hydro One Connection Work:

(a) Hydro One shall own, operate and maintain all equipment specified in Schedule "A" of the Agreement under the heading "Ownership"; and

(b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit Connection of the New or Modified Connection Facilities to Hydro One's transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

9. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule "B" of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
(iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
(v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
(vi) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contributions paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule "B". If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "B".

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

(a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs;
(b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer; or
(c) the construction of or modifications to Hydro One's Network Facilities that may be required to accommodate the New or Modified Connection other than Network Customer Allocated Work unless Hydro One has indicated in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution.

10.3 Notwithstanding Sub-section 10.2(c) above, if Hydro One indicates in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution towards the Network Pool Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 20 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof and where this Capital Contribution includes the cost of capacity on the Connection Facility not needed by the Customer as indicated in Schedule "B" of the Agreement, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.2.25 of the *Transmission System Code* if that capacity is assigned to another Load Customer within five (5) years of the In Service Date.

11. Hydro One shall perform a True-Up, based on Actual Load:

(a) at the True-Up Points specified in Schedule "A" of the Agreement; and
(b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

(i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

(ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code*.

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code)* during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the Transmission System Code when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14. Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code*.

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1 The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described asWork Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "B" of the Agreement in the manner specified in Schedule "B" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or
(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 18 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the

Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 **Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility:** If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, at least 30 days prior to transferring load from the Existing Load Facility Hydro One will then proceed in accordance with Section 6.7 of the *Transmission System Code*.

17.2 **Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load:** Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One or the OEB, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential by-pass situation in accordance with the OEB-Approved Connection Procedures. If the Customer does not intend to by-pass the Existing Load Facility, the Customer must in accordance with the OEB-Approved Connection Procedures:

i. notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's Existing Load Facility;
ii. transfer the load back to the Existing Load Facility within an agreed time period; and
iii. compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be a term of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or
(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus Taxes) which become payable under this Section 18 within 30 calendar days after the date of invoice.

Part F: Sale, Lease, Transfer or Other Disposition of Customer's Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash, letter of credit or surety bond, the Customer shall furnish such security in the amount and by the dates specified in Schedule "A" of the Agreement. Hydro One shall return the security deposit to the Customer as follows:

(i) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and

(ii) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. Prior to the existence of OEB-Approved Connection Procedures either party may refer a Dispute to the OEB for a determination. Once there are OEB-Approved Connection Procedures, all disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is constructing the New or Modified Connection Facilities, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement.

Part I: Easement

24. If specified in Schedule "A" that an easement(s) is required from the Customer, the Customer shall grant an easement to Hydro One substantially in the form of the easement attached hereto as Appendix "B" of these

Standard Terms and Conditions for the property(ies) described as the Easement Lands in Schedule "A" on or before the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 18 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

(i) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or

(ii) the amounts payable under Section 16 and 18 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms

of this Agreement and the parties shall follow the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the Parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

34. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice shall be deemed to be received on the date of the fax if received before 3 p.m. on a business day or on the next business day if received after 3 p.m. or a day that is not a business day. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

37. The Customer shall provide Hydro One with a copy of the Customer's final monthly bills associated

with the transmission of electricity from the Existing Load Facilities and/or the Customer's Facilities or authorize the IESO to provide Hydro One with same. Hydro One agrees to use this information solely for the purpose of the Agreement.

38. **Invoices and Interest:** Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

39. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 18 or 23 shall survive the termination of the Agreement.

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

"Assigned Capacity" is calculated in accordance with Section 6.2.2 of the *Transmission System* Code.

"Adjusted Load Forecast" means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 5(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code*.

"Connect and Connection" has the same meaning ascribed to the term "Connect" in the *Transmission System Code*.

"Connection Agreement" means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

"Connection Facilities" has the meaning set forth in the *Transmission System Code*.

"Connection Point" has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule "A" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer Connection Risk Classification" is as specified in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer's Facilities.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Dispute" means a dispute between the Parties with respect to any of the matters listed in Section 6.1.4 of the *Transmission System Code* where either Party is alleging that the other is seeking to impose a term that is inconsistent or contrary to the *Ontario Energy Board Act*, the *Electricity Act, 1998*, Hydro One's transmission licence or the *Transmission System Code* or refusing to include a term or condition that is required to give effect to the Code.

"Distributor" has the meaning set forth in the *Transmission System Code*.

"Economic Evaluation Period" means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule "A" of the Agreement.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"*Electricity Act, 1998*" means the *Electricity Act, 1998* being Schedule "A" of the *Energy Competition Act,* S.O. *1998*, c.15, as amended.

"Existing Load" in relation to the Customer and each of the Existing Load Facilities is equal to the Customer's Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

"Existing Load Facility or Existing Load Facilities" means the connection facility(ies) owned by Hydro One as specified in the Existing Load Table in Schedule "A" of the Agreement where the Customer has Existing Load.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"GST" means the Goods and Services Tax.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means Hydro One's structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the *Electricity Act, 1998*.

"In Service Date" has the same meaning ascribed to the term "comes into service" in the *Transmission System Code*.

"Incremental Network Load" means the Customer's New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

"Interest" means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code*.

"Line Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Line Connection Pool Work".

"Line Connection Revenue" means the amount of line connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

"Line Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Load Customer" has the meaning set forth in the *Transmission System Code*.

"Load Forecast" means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Network Customer Allocated Work" means the construction of or modifications to Network Facilities specified in Schedule "A" of the Agreement under the heading "Network Customer Allocated Work" that are minimum connection requirements.

"Network Facilities" has the meaning set forth in the *Transmission System Code*.

"Network Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Network Pool Work".

"Network Revenue" means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

"Network Service Rate" " means the network service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"New Load" means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "A" of the Agreement.

"Normal Capacity" means, where the Customer is:

(a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and

(b) one of two or more Load Customers served by an Existing Load Facility, the Customer's pro-rated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Pool-Funded Cost" means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"**Rate Order"** has the meaning ascribed thereto in the *Transmission System Code.*

"Ready for Service Date" means the date upon which the Hydro One Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Standard Terms and Conditions" means these Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects and Appendices "A" and "B" attached hereto.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"Transformation Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code.*

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code.*

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

Appendix "B": Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of ______________________________
____
____ (the "**Lands**").

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the "**Rights**") in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the "**Strip**") for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the "**Works**") as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the "**obstruction**") whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set his hand and seal to this Agreement, this ___ day of _______ ______________, 200__.

SIGNED, SEALED AND DELIVERED
In the presence of)
) ___________________________________)
__________________________________(seal)
Signature of Witness) Transferor's Signature
)
)
)
__________________________________) ______________________________(seal)
Signature of Witness Transferor's Signature

)
SIGNED, SEALED AND DELIVERED) Consent Signature & Release of
In the presence of) Transferor's Spouse, if non-owner.
)
)
)
__________________________________) ______________________________(seal)
Signature of Witness

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated ____________________

Between ________________________________ and ____

and registered as Instrument Number ___________________ on ______________________________ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name Signature(s) Date of Signatures
Y M D

Per:

____

____

I/We have authority to bind the Corporation

Burlington Hydro Revised Schedule "B" (Tremaine TS)

This updated Schedule B is part of the CCRA and includes actual costs.

SCHEDULE B REVISION DATE

July 30, 2013

READY FOR SERVICE DATE

December 17, 2012

Costs of the Project are being apportioned between the Customer and Milton Hydro Distribution Inc. based on the Customer having 75% of the 153MW available capacity at Tremaine TS and Milton Hydro Distribution Inc. having 25%. As such, the Customer will be responsible for 75% of the total cost of the Project.

The Customer will have 114.75MW of contracted capacity at Tremaine TS.

The Customer will initially have six (6) feeder positions at Tremaine TS.

The assignment of overload credits at Palermo TS is based on the Customer's loads which exceed assigned capacity, as shown in Column "B" of the "Existing Load" Table.

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work:
Total Project Cost: $28,301,225.00
Cost Allocated to the Customer: $21,225,919.00

Estimate of Transformation Connection Pool Work Capital Contribution: $9,142,600.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work:
Total Project Cost**:** $21,008,867.00
Cost Allocated to the Customer: $15,756,650.00

Actual Transformation Connection Pool Work Capital Contribution: $3,796,100.00

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: No

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work:
Total Project Cost: $1,267,806.00
Cost Allocated to the Customer: $950,855.00

Estimate of Line Connection Pool Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Line Connection Pool Work:
Total Project Cost**:** $889,248.00
Cost Allocated to the Customer: $666,936.00

Actual Line Connection Pool Work Capital Contribution: $0

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: N/A

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work:

Total Project Cost: $431,442.00
Cost Allocated to the Customer: $323,582.00

Estimate of Network Customer Allocated Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Network Customer Allocated Work:
Total Project Cost: $465,715.00
Cost Allocated to the Customer: $349,286.00

Actual of Network Customer Allocated Work Capital Contribution: $0

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable from Customer) is $0. Subject to Sections 10.3 and 18 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $550,457.00 comprised of:

For Revenue Metering Instrument Transformers: $485,457.00
For Feeder Duct Banks: $65,000.00

Actual Engineering and Construction Cost of the Work Chargeable to Customer: $317,502.00

For Revenue Metering Instrument Transformers: $288,326.00
For Feeder Duct Banks: $29,176.00

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
April 15, 2011	$892,600.00	0	0	$50,457.00	$943,057.00
January 15, 2012	$2,750,000.00	0	0	$145,000.00	$2,895,000.00
October 15, 2012	$2,750,000.00	0	0	$210,000.00	$2,960,000.00
January 30, 2013	$2,750,000.00	0	0	$145,000.00	$2,895,000.00
Total	**$9,142,600.00**	**0**	**0**	**$550,457.00**	**$9,693,057.00**

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities **[A]** (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	32.6	32.6	32.6	692.5
2nd Anniversary of In Service Date	36.2	36.2	36.2	768.7
3rd Anniversary of In Service Date	39.9	39.9	39.9	846.6
4th Anniversary of In Service Date	43.4	43.4	43.4	922.8
5th Anniversary of In Service Date	47.1	47.1	47.1	1,000.70
6th Anniversary of In Service Date	50.7	50.7	50.7	1,076.90
7th Anniversary of In Service Date	54.3	54.3	54.3	1,153.10
8th Anniversary of In Service Date	58	58	58	1,230.90
9th Anniversary of In Service Date	61.5	61.5	61.5	1,307.20
10th Anniversary of In Service Date	65.1	65.1	65.1	1,383.40
11th Anniversary of In Service Date	68.6	68.6	68.6	1,457.90
12th Anniversary of In Service Date	71.8	71.8	71.8	1,525.80
13th Anniversary of In Service Date	74.7	74.7	74.7	1,587.10
14th Anniversary of In Service Date	77.2	77.2	77.2	1,640.20
15th Anniversary of In Service Date	79.4	79.4	79.4	1,686.50
16th Anniversary of In Service Date	81	81	81	1,719.70
17th Anniversary of In Service Date	82.2	82.2	82.2	1,746.20
18th Anniversary of In Service Date	83.1	83.1	83.1	1,766.10
19th Anniversary of In Service Date	83.9	83.9	83.9	1,782.60
20th Anniversary of In Service Date	84.8	84.8	84.8	1,800.90

21st Anniversary of In Service Date	85.6	85.6	85.6	1,817.40
22nd Anniversary of In Service Date	86.3	86.3	86.3	1,834.00
23rd Anniversary of In Service Date	87.2	87.2	87.2	1,852.20
24th Anniversary of In Service Date	88	88	88	1,868.80
25th Anniversary of In Service Date	88.8	88.8	88.8	1,885.30

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	32.6	32.6	4.2	40
2nd Anniversary of In Service Date	36.2	36.2	4.7	44.4
3rd Anniversary of In Service Date	39.9	39.9	5.2	49
4th Anniversary of In Service Date	43.4	43.4	5.6	53.4
5th Anniversary of In Service Date	47.1	47.1	6.1	57.9
6th Anniversary of In Service Date	50.7	50.7	6.6	62.3
7th Anniversary of In Service Date	54.3	54.3	7	66.7
8th Anniversary of In Service Date	58	58	7.5	71.2
9th Anniversary of In Service Date	61.5	61.5	8	75.6
10th Anniversary of In Service Date	65.1	65.1	8.4	80
11th Anniversary of In Service Date	68.6	68.6	8.9	84.3
12th Anniversary of In Service Date	71.8	71.8	9.3	88.2
13th Anniversary of In Service Date	74.7	74.7	9.7	91.8
14th Anniversary of In Service Date	77.2	77.2	10	94.8
15th Anniversary of In Service Date	79.4	79.4	10.3	97.5
16th Anniversary of In Service Date	81	81	10.5	99.4
17th Anniversary of In Service Date	82.2	82.2	10.7	101
18th Anniversary of In Service Date	83.1	83.1	10.8	102.1
19th Anniversary of In Service Date	83.9	83.9	10.9	103.1
20th Anniversary of In Service Date	84.8	84.8	11	104.1
21st Anniversary of In Service Date	85.6	85.6	11.1	105.1
22nd Anniversary of In Service Date	86.3	86.3	11.2	106
23rd Anniversary of In Service Date	87.2	87.2	11.3	107.1
24th Anniversary of In Service Date	88	88	11.4	108.1
25th Anniversary of In Service Date	88.8	88.8	11.5	109

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	32.6	32.6	4.2	40
2nd Anniversary of In Service Date	36.2	36.2	4.7	44.4
3rd Anniversary of In Service Date	39.9	39.9	5.2	49
4th Anniversary of In Service Date	43.4	43.4	5.6	53.4
5th Anniversary of In Service Date	47.1	47.1	6.1	57.9
6th Anniversary of In Service Date	50.7	50.7	6.6	62.3
7th Anniversary of In Service Date	54.3	54.3	7	66.7
8th Anniversary of In Service Date	58	58	7.5	71.2
9th Anniversary of In Service Date	61.5	61.5	8	75.6
10th Anniversary of In Service Date	65.1	65.1	8.4	80
11th Anniversary of In Service Date	68.6	68.6	8.9	84.3
12th Anniversary of In Service Date	71.8	71.8	9.3	88.2
13th Anniversary of In Service Date	74.7	74.7	9.7	91.8
14th Anniversary of In Service Date	77.2	77.2	10	94.8
15th Anniversary of In Service Date	79.4	79.4	10.3	97.5
16th Anniversary of In Service Date	81	81	10.5	99.4
17th Anniversary of In Service Date	82.2	82.2	10.7	101
18th Anniversary of In Service Date	83.1	83.1	10.8	102.1
19th Anniversary of In Service Date	83.9	83.9	10.9	103.1
20th Anniversary of In Service Date	84.8	84.8	11	104.1
21st Anniversary of In Service Date	85.6	85.6	11.1	105.1
22nd Anniversary of In Service Date	86.3	86.3	11.2	106
23rd Anniversary of In Service Date	87.2	87.2	11.3	107.1
24th Anniversary of In Service Date	88	88	11.4	108.1
25th Anniversary of In Service Date	88.8	88.8	11.5	109

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

****** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

THIS AMENDING AGREEMENT made effective as of the last date on the signature page (the "**Effective Date**")

BETWEEN:

HYDRO ONE NETWORKS INC., a corporation incorporated pursuant to the laws of the Province of Ontario, (hereinafter referred to as "**Hydro One**") and licensed by the OEB.

OF THE FIRST PART;

- and -

BURLINGTON HYDRO INC. (hereinafter referred to as the "**Customer**")

OF THE SECOND PART.

From time to time, Hydro One and the Customer shall be individually referred to in this Agreement as "Party" and collectively as "Parties".

WHEREAS:

1. Hydro One and the Customer entered into a Connection and Cost Recovery Agreement dated March 30, 2011 (the "**Agreement**") in respect of the connection of the new Tremaine Transmission Station to Hydro One's transmission system; and

3. the parties intend to amend Schedules "A" and "B" of the Agreement in the manner set out herein to reflect the addition of the installation of feeder duct banks to the scope of the Work Chargeable to Customer.

NOW THEREFORE, in consideration of the foregoing, and of the mutual covenants, agreements, terms and conditions herein contained, the Parties, intending to be legally bound, hereby agree as follows:

1. Each of the parties represents and warrants that the recitals, to the extent that the recitals are applicable to that party, are true and accurate and form part of this Amending Agreement.

2. All terms which are defined in the Agreement and which appear in this Amending Agreement without definition, shall have the meanings respectively ascribed thereto in the Agreement.

3. The Agreement is hereby amended by:

(i) Deleting Section 2 of Part 5 of Schedule "A" and replacing it with the following:

2. Feeder Duct Banks

Hydro One will:

- Excavate a trench to the depth specified in Drawing #1 attached to this Agreement in as Schedule "C" ("**Drawing #1**") up to 1.2 m outside the station fence to avoid fence grounding.

CBR00191

- Install six (6) DB2 ducts and fill the trench with concrete as shown in Drawing #1 and Drawing #2 attached to this Agreement in as Schedule "C".
- Cap the ducts at both ends and back fill.

(ii) Deleting the Work Chargeable to Customer and the Manner Of Payment of the Estimate Of Capital Contributions and Work Chargeable To Customer set out in Schedule "B" and replacing it with the following:

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $550,457.00 comprised of:

For Revenue Metering Instrument Transformers: $485,457.00
For Feeder Duct Banks: $65,000.00

Actual Engineering and Construction Cost of the Work Chargeable to Customer: To be provided 180 days after Ready for Service Date.

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
April 15, 2011	$892,600.00	0	0	$50,457.00	$943,057.00
January 15, 2012	$2,750,000.00	0	0	$145,000.00	$2,895,000.00
October 15, 2012	$2,750,000.00	0	0	$210,000.00	$2,960,000.00
January 30, 2013	$2,750,000.00	0	0	$145,000.00	$2,895,000.00
Total	**$9,142,600.00**	**0**	**0**	**$550,457.00**	**$9,693,057.00**

(iii) Adding Appendix I to this Amending Agreement as Schedule "C" of the Agreement.

4. The parties do hereby reconfirm that the terms and conditions of the Agreement as amended by this Amending Agreement shall continue to be in full force and effect.

5. This Amending Agreement and each of the Parties' respective rights and obligations under this Amending Agreement, shall be binding on and shall inure to the benefit of the Parties hereto and each of their respective successors and permitted assigns.

6. This Amending Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

IN WITNESS WHEREOF, the Parties hereto, intending to be legally bound, have caused this Amending Agreement to be executed by the signatures of their proper officers duly authorized in their behalf.

HYDRO ONE NETWORKS INC.

Bradley Colden

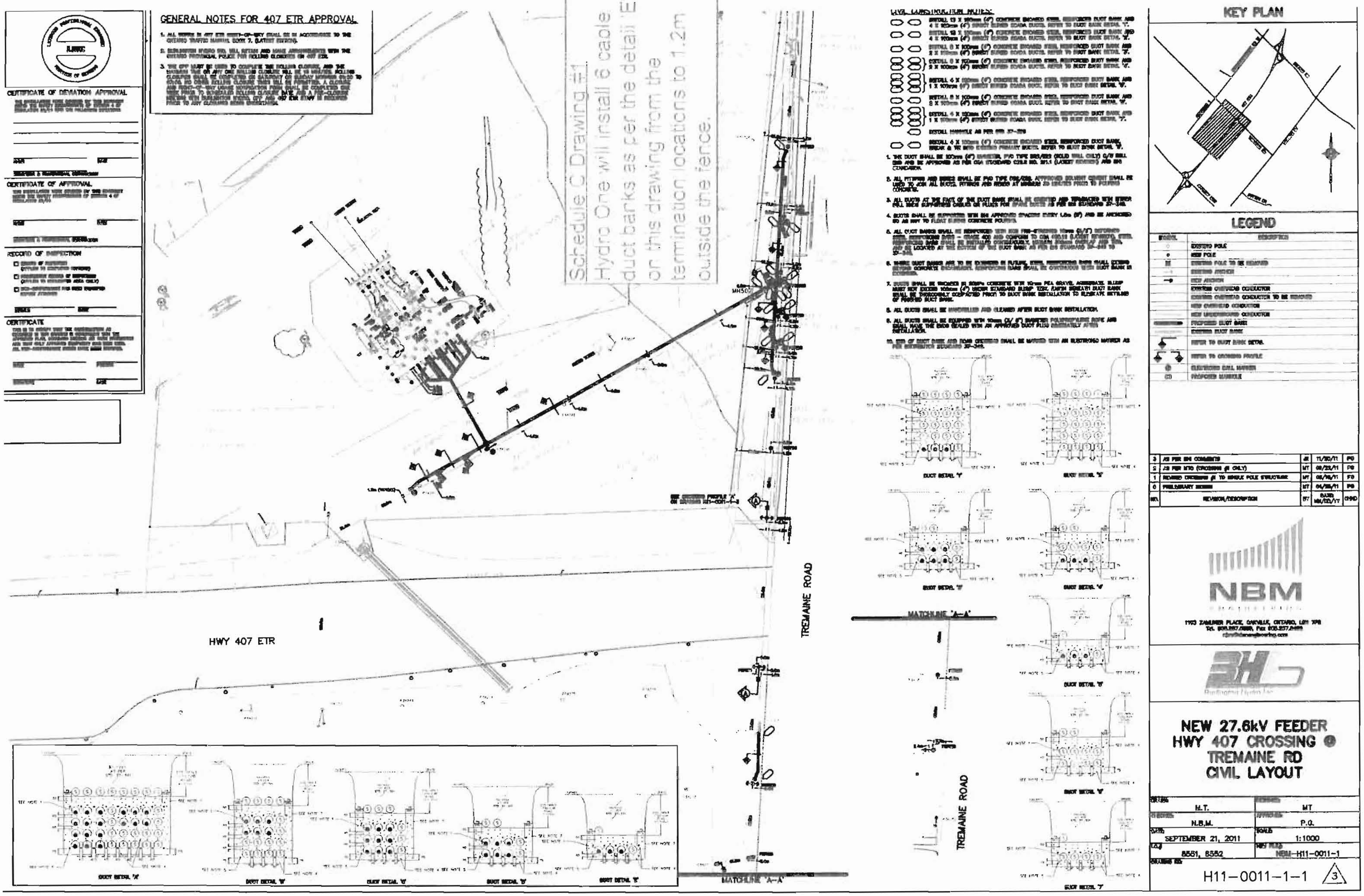
Name: Brad Colden
Title: Manager – Customer Business Relations
Date: June 28, 2012
I have the authority to bind the Corporation

BURLINGTON HYDRO INC.

Name: Gerry Smallegange
Title: President & CEO
Date: June 21/12
I have the authority to bind the Corporation

Appendix I to Amending Agreement:

Schedule "C": Drawing #1 and #2



Schedule C Drawing #1
Hydro One will install 6 cable duct banks as per the detail 'E' on this drawing from the termination locations to 1.2m outside the fence.

Schedule C Drawing #2
Hydro One will install 6 cable
duct banks as per the detail 'E'
on this drawing from the
termination locations to 1.2m
outside the fence.
HYDRO TOWER
1.9m
4.0m
T36B
T37B
1.0m
1.0m
5.9m
11.3m
7SC1
7SC2
27.6kV AREA
4,000m ROAD
IT.157A
IT.195A TWR.
HYDRO TOWER
T38B
T39B

Connection and Cost Recovery Agreement

between

Burlington Hydro Inc.

and

Hydro One Networks Inc.

for

Tremaine Transformer Station

Burlington Hydro Inc. (the "**Customer**") has requested and **Hydro One Networks Inc.** ("**Hydro One**") has agreed to build a new 230/27.6 kV, 75/100/125 MVA Transformer Station in the vicinity of Tremaine Road and Hwy 407 in the City of Burlington (the "**Project**") on the terms and conditions set forth in this Agreement dated March 30, 2011 (the "**Agreement**") and the attached Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects V3 9-2007 R5 (the "**Standard Terms and Conditions**" or "**T&C**"). Schedules "A" and "B" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

The Customer's load in North Burlington has exceeded the available capacity of Hydro One's transformation facilities, specifically, Palermo TS, which currently serves the Customer, Milton Hydro Distribution Inc. and Oakville Hydro Electricity Distribution Inc. The Customer has advised Hydro One that it will require new transformation capacity to supply existing capacity shortfall as well as its future load growth requirements. Hydro One will design and construct a 230/27.6 kV, 75/100/125 MVA transformer station, Tremaine TS, on the west side of Tremaine Road, north of Hwy 407 in the City of Burlington to supply the Customer and Milton Hydro Distribution Inc.

Term: The term of this Agreement will commence on the date that is the latter of the date that:

(a) this Agreement is fully executed by the Customer and Hydro One; and
(b) Milton Hydro Distribution Inc. executes and delivers the Connection and Cost Recovery Agreement to be made between Hydro One and Milton Hydro Distribution Inc. for the Project,

and will terminate on the 25th anniversary of the In Service Date.

Special Circumstances:

The Customer acknowledges that the cost of the Project will be shared between the Customer and Milton Hydro Distribution Inc. Seventy-five percent (75%) of the capacity of Tremaine TS is to be allocated to the Customer, with the remainder allocated to Milton Hydro Distribution Inc. Costs are to be shared in accordance with the proportion of assigned capacity.

Hydro One acknowledges that the Customer bears no responsibility whatsoever for the portion of the costs payable by and revenues to be received from Milton Hydro Distribution Inc. in respect of the Project.

In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to:

(a) the Customer executing and delivering this Agreement to Hydro One by no later than **April 15, 2011;** and
(b) Milton Hydro Distribution Inc. executing and delivering the Connection and Cost Recovery Agreement to be made between Hydro One and Milton Hydro Distribution Inc. for the Project by no later than **April 15, 2011**.

Subject to Section 31, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Brad Colden
Manager - Customer Business Relations
I have the authority to bind the Corporation.

BURLINGTON HYDRO INC.

Gerry Smallegange
President & CEO
I have the authority to bind the Corporation.

MICHAEL KYSLEY
EVP & CFO

Schedule "A" (Tremaine TS)

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will design, construct, own and operate a new 75/125 MVA, 230/27.6 kV DESN, Tremaine TS, to be located at a new site located at Tremaine Road and just north of Highway 407 in the City of Burlington ("**Tremaine TS**").

Connection Point: 230 kV transmission circuits, T38B and T39B, approximately 4 kilometres west of Hydro One's Palermo TS.

Ready for Service Date: January 31, 2013

HYDRO ONE CONNECTION WORK

Part 1:Transformation Connection Pool Work

Hydro One will:
Design and build Tremaine TS as described below:

1. General Requirement
- Obtain approvals and permits as required for the stations facilities. These include, and are not necessarily limited to those related to noise, soil removals, drainage, and landscaping.
- Carry out acceptance checks, testing and commissioning of station equipment and associated systems.
- Provide perimeter chain-link fencing and access gate.
- Provide required site drainage.
- Provide required station access roads.
- Provide landscaping.

2. 230 kV Switchyard
- Provide and install two (2) 230 kV motorized disconnect switches to meet the requirements of the line tap and to interrupt the maximum transformer magnetizing current.
- Provide and install two (2) 75/100/125 MVA, 230/27.6-27.6 kV transformers as per CSA standards with a minimum summer 10 day LTR of 170 MVA.
- Provide and install transformer cooler and conservator tanks.
- Provide and install spill containment around the two transformers, as required by the Ministry of Environment.
- Provide and install six (6) phase-to-ground HV station class surge arresters, one for each phase of the HV bushings.
- Provide and install all required insulators, support structures, foundations and 230 kV cabling connecting the above equipment.

3. 27.6 kV Switching Facilities
The LV switchyard will be designed to allow for overhead egress of the eight (8) feeders (future twelve (12)). Scope of work includes the following:
- Provide and install twelve (12) LV station class surge arresters.
- Provide and install four (4) 1.5 ohm neutral reactors.
- Provide and install two (2) 27.6 kV main buses.
- Provide and install four (4) 2500 Ampere LV transformer breakers each with two (2) isolating switches.

- Provide and install one (1) normally open 2500 Ampere bus tie breaker with two (2) isolating switches.
- Provide and install eight (8) 1200 Ampere feeder breakers each with associated isolating switches. Six (6) feeder breakers will be for the Customer's use.
- Provide space for an additional four (4) feeder breakers and associated isolating switches.
- Provide and install bus work between the main buses and the feeder breakers.
- Provide and install four (4) three-phase feeder tie switches.
- Provide and install eight (8) protections sets of instrument transformers (potential and current transformers) for protection purposes.
- Provide and install eight (8) sets of feeder buses connecting the feeder breakers, the feeder tie switches and the Customer's feeders.
- Provide and install all required insulators, support structures, foundations and LV cabling connecting the above equipment.
- Provide space for two (2) future 27.6 kV capacitor banks and associated breakers.

4. AC and DC Station Service Systems

- Provide and install a complete AC Station Service System including two (2) pad-mounted Station Service Transformers with associated fusing, insulators, transfer switches, breakers, disconnect switches, panels and cabling.
- Provide a complete DC Station Service System as part of a pre-wired PCT building.

5. Protection, Control and Teleprotections Systems

- Provide and install a pre-fabricated & pre-wired PCT building.
- Review and revise, as required, the line protections on T38B and T39B.
- Review and advise the Customer as to any required changes to line protections on T38B and T39B.
- Provide SCADA communications to OGCC and IESO.
- Provide under-frequency load shedding relaying, as required.
- Witness P&C building manufacturer commissioning.
- Commission all P&C devices associated with the new facilities as well as at existing facilities connected to 230 kV circuits, T38B and T39B.
- Provide final single line diagram & confirm protection settings.

6. Grounding and Lightning Protection

- Provide and install station ground grid in the new switchyard.
- Provide grounding for the new sections of station fence.
- Provide standard grounding for the power transformers, HV and LV surge arresters, HV and LV switches, breakers and all steel structures.
- Provide perimeter grounding for the PCT building and connect to the grounding bus inside the PCT building.
- Provide lightning protection at the TS, as required.

7. Exclusions/Assumptions

Cost estimates are based on the following assumptions:

- Sound attenuation measures are not included in this scope of work as their need has yet to be verified.
- Soil conditions and resistivity at the site is good.
- Excavated soil is not contaminated.

8. Property Procurement

- Purchase property required for Tremaine TS.
- Obtain Environmental Assessment and all other permits/approvals associated with the or required for Tremaine TS or the 230 kV line connections.
- Permits and approvals associated with the distribution feeders are the responsibility of the Customer.

<u>NOTES:</u>

None.

Part 2: Line Connection Pool Work

Hydro One will:

- Provide 230 kV line taps from circuits T38B and T39B to the station line terminating structures.
- Provide 230 kV mid-span openers on the line taps.

<u>NOTES:</u>

None.

Part 3: Network Customer Allocated Work

Hydro One will:

- Revise, own and maintain tele-protections for circuits T38B and T39B as required to accommodate the New or Modified Connection Facility.
- Modify existing master SCADA at Hydro One's Ontario Grid Control Centre (OGCC) to provide control of the New or Modified Connection Facility

Part 4: Network Pool Work (Non-Recoverable from Customer)

Hydro One will:

Not Applicable.

Part 5: Work Chargeable to Customer

Hydro One will:

1. Revenue Metering Instrument Transformers

- Specify, supply, install and connect twelve (12) Revenue Canada approved revenue metering potential transformers (PTs) and twelve (12) free standing Revenue Canada approved revenue metering current transformers (CTs) on LV bus structures. The bus structure is to be modified to accommodate the installation.
- Provide four (4) metering junction boxes on the structure supporting the revenue metering CTs.
- Supply, install and terminate the secondary cables from the instrument transformer terminal boxes to metering junction boxes and to the metering cabinets provided by the Customer.
- Install and terminate 120 VAC Station Service cables from AC Station Service Distribution panel to the metering cabinets provided by the Customer.
- Install and terminate telephone service cables from telecom cable interface box to metering cabinets provided by the Customer.
- Install the structure supporting the Customer's metering cabinets to a location outside the PCT building.
- Providing spare instrument transformers are NOT included in the scope of work.

2. Feeder Duct Banks

- Provision by Hydro One of feeder duct banks within the station fence, if required, is NOT covered by this Agreement. If the Customer wishes to have Hydro install feeder duct banks, this work would be dealt with by a separate agreement.

NOTES:

None

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- requirement for Hydro One to obtain approval under Section 92 (leave to construct) of the *Ontario Energy Board Act* if the transmission line route selected by Hydro One is greater than 2 km in length;
- Hydro One having to expropriate property under the *Ontario Energy Board Act;*
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the *Ontario Energy Board Act* or any approval issued by the OEB to expropriate under the *Ontario Energy Board Act*; and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Transformation Connection Pool Work,;
(ii) the Line Connection Pool Work;
(iii) Network Pool Work
(iv) Network Customer Allocated Work; and
(v) the Work Chargeable to Customer.

At that point, no further Non-Customer initiated scope changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

The Customer will:

- Provide the revenue metering instrument transformers for installation by Hydro One. These must be dedicated instrument transformers which satisfy the latest IESO requirements.
- Provide and install revenue metering cabinets and associated metering equipment and cabling.
- Order a landline telephone service for IESO MV90 access and ensure that the service is available at least two weeks prior to in-service date.
- Accept responsibility for the registration of the revenue metering installations. The IESO registration work must be completed at least two weeks prior to the in-service date.
- Accept responsibility for purchasing and storing any spare equipment associated with the revenue metering installation (including instrument transformers).
- Provide and install 27.6 kV feeder conductors.
- Provide and install the drop leads to make connection to NEMA pads at feeder disconnect switches.
- Provide feeder protection settings for implementation by Hydro One.

The Customer will be responsible for the cost of feeder duct banks, if required, within the station fence.

EXISTING LOAD:

	A	B		
Existing Load Facility	**Existing Load (MW)[1,]**	**Normal Capacity (MW)[2]**		
Burlington TS	156.0	156.0		
Bronte TS (T2)	30.0	30.0		
Cumberland TS	148.2	148.2		
Palermo TS	30.7	30.7		
Total	364.9	364.9		

Notes:

1. Existing Load means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the *Transmission System Code).*
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the *Transmission System Code* and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.
3. "Normal Capacity" value shown is for the portion of the facility's capacity which is available for supplying the Customer.
4. Where the "Existing Load" has exceeded the "Normal Capacity", the "Existing Load" has been set equal to the "Normal Capacity".

<u>OTHER RELEVANT CONSIDERATIONS:</u> None

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR ODIFICATIONS:

None

MISCELLANEOUS

Customer Connection Risk Classification: Low Risk

True-Up Points: **If Low Risk** (a) following the fifth and tenth anniversaries of the In Service Date; and
(b) following the fifteenth anniversary of the In Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's HST Registration Number: 868291980RT

Documentation Required (after In Service Date): Feeder egress drawings

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work.

Approval Date (if Section 92 required to be obtained by Hydro One): Not required

Security Requirements: Nil

Security Date: Nil

Easement Required from Customer: No

Easement Date: Not applicable

Easement Lands: Not applicable

Easement Term: Not applicable

Approval Date (for OEB leave to construct): Not required

Revenue Metering: IESO compliant revenue metering to be provided by the Customer.

Customer Notice Info:

Burlington Hydro Inc.
P.O. Box 5018
1340 Brant Street
Burlington, Ontario
L7R 3Z7

Attention: Joe Saunders, Director, Regulatory Compliance and Asset Management
Fax #: 905-332-0684

Schedule "B" (Tremaine TS)

Costs of the Project are being apportioned between the Customer and Milton Hydro Distribution Inc. based on the Customer having 75% of the 153MW available capacity at Tremaine TS and Milton Hydro Distribution Inc. having 25%. As such, the Customer will be responsible for 75% of the total cost of the Project.

The Customer will have 114.75MW of contracted capacity at Tremaine TS.

The Customer will initially have six (6) feeder positions at Tremaine TS.

The assignment of overload credits at Palermo TS is based on the Customer's loads which exceed assigned capacity, as shown in Column "B" of the "Existing Load" Table.

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work:
Total Project Cost: $28,301,225.00
Cost Allocated to the Customer: $21,225,919.00

Estimate of Transformation Connection Pool Work Capital Contribution: $9,142,600.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Transformation Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: No

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work:
Total Project Cost: $1,267,806.00
Cost Allocated to the Customer: $950,855.00

Estimate of Line Connection Pool Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Line Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Line Connection Pool Work Capital Contribution: To be provided 180 days after Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: N/A

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work:

Total Project Cost: $431,442.00
Cost Allocated to the Customer: $323,582.00

Estimate of Network Customer Allocated Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Network Customer Allocated Work: To be provided 180 days after Ready for Service Date

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable from Customer) is $0. Subject to Sections 10.3 and 18 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer:
For Revenue Metering Instrument Transformers: $485,457.00

Actual Engineering and Construction Cost of the Work Chargeable to Customer: To be provided 180 days after Ready for Service Date.

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
April 15, 2011	$892,600	0	0	$50,457	$943,057
Jan 15, 2012	$2,750,000	0	0	$145,000	$2,895,000
Oct 15, 2012	$2,750,000	0	0	$145,000	$2,895,000
Jan 30, 2013	$2,750,000	0	0	$145,000	$2,895,000
Total	**$9,142,600**	**0**	**0**	**$485,457**	**$9,628,057**

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	32.9	32.9	32.9	698.9
2nd Anniversary of In Service Date	36.5	36.5	36.5	775.2
3rd Anniversary of In Service Date	40.2	40.2	40.2	852.9
4th Anniversary of In Service Date	43.8	43.8	43.8	929.3
5th Anniversary of In Service Date	47.4	47.4	47.4	1007.0
6th Anniversary of In Service Date	51.0	51.0	51.0	1083.2
7th Anniversary of In Service Date	54.6	54.6	54.6	1159.6
8th Anniversary of In Service Date	58.3	58.3	58.3	1237.3
9th Anniversary of In Service Date	61.8	61.8	61.8	1313.5
10th Anniversary of In Service Date	65.4	65.4	65.4	1389.6
11th Anniversary of In Service Date	68.9	68.9	68.9	1463.6
12th Anniversary of In Service Date	72.1	72.1	72.1	1530.9
13th Anniversary of In Service Date	74.9	74.9	74.9	1591.6
14th Anniversary of In Service Date	77.4	77.4	77.4	1644.0
15th Anniversary of In Service Date	79.5	79.5	79.5	1689.3
16th Anniversary of In Service Date	81.1	81.1	81.1	1721.9
17th Anniversary of In Service Date	82.3	82.3	82.3	1747.8
18th Anniversary of In Service Date	83.2	83.2	83.2	1767.4
19th Anniversary of In Service Date	84.0	84.0	84.0	1784.1
20th Anniversary of In Service Date	84.9	84.9	84.9	1802.2
21st Anniversary of In Service Date	85.6	85.6	85.6	1818.8
22nd Anniversary of In Service Date	86.4	86.4	86.4	1835.5
23rd Anniversary of In Service Date	87.3	87.3	87.3	1853.6
24th Anniversary of In Service Date	88.0	88.0	88.0	1870.2
25th Anniversary of In Service Date	88.8	88.8	88.8	1886.7

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	32.9	32.9	6.1	57.4
2nd Anniversary of In Service Date	36.5	36.5	6.7	63.6
3rd Anniversary of In Service Date	40.2	40.2	7.4	70.0
4th Anniversary of In Service Date	43.8	43.8	8.0	76.3
5th Anniversary of In Service Date	47.4	47.4	8.7	82.7
6th Anniversary of In Service Date	51.0	51.0	9.4	88.9
7th Anniversary of In Service Date	54.6	54.6	10.0	95.2
8th Anniversary of In Service Date	58.3	58.3	10.7	101.6
9th Anniversary of In Service Date	61.8	61.8	11.4	107.8
10th Anniversary of In Service Date	65.4	65.4	12.0	114.1
11th Anniversary of In Service Date	68.9	68.9	12.7	120.1
12th Anniversary of In Service Date	72.1	72.1	13.3	125.7
13th Anniversary of In Service Date	74.9	74.9	13.8	130.6
14th Anniversary of In Service Date	77.4	77.4	14.2	135.0
15th Anniversary of In Service Date	79.5	79.5	14.6	138.7
16th Anniversary of In Service Date	81.1	81.1	14.9	141.3
17th Anniversary of In Service Date	82.3	82.3	15.1	143.5
18th Anniversary of In Service Date	83.2	83.2	15.3	145.1
19th Anniversary of In Service Date	84.0	84.0	15.4	146.5
20th Anniversary of In Service Date	84.9	84.9	15.6	147.9
21st Anniversary of In Service Date	85.6	85.6	15.7	149.3
22nd Anniversary of In Service Date	86.4	86.4	15.9	150.7
23rd Anniversary of In Service Date	87.3	87.3	16.1	152.2
24th Anniversary of In Service Date	88.0	88.0	16.2	153.5
25th Anniversary of In Service Date	88.8	88.8	16.3	154.9

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	32.9	32.9	0.5	19.5
2nd Anniversary of In Service Date	36.5	36.5	0.6	21.7
3rd Anniversary of In Service Date	40.2	40.2	0.6	23.8
4th Anniversary of In Service Date	43.8	43.8	0.7	26.0
5th Anniversary of In Service Date	47.4	47.4	0.7	28.2
6th Anniversary of In Service Date	51.0	51.0	0.8	30.3
7th Anniversary of In Service Date	54.6	54.6	0.8	32.4
8th Anniversary of In Service Date	58.3	58.3	0.9	34.6
9th Anniversary of In Service Date	61.8	61.8	1.0	36.7
10th Anniversary of In Service Date	65.4	65.4	1.0	38.8
11th Anniversary of In Service Date	68.9	68.9	1.1	40.9
12th Anniversary of In Service Date	72.1	72.1	1.1	42.8
13th Anniversary of In Service Date	74.9	74.9	1.2	44.5
14th Anniversary of In Service Date	77.4	77.4	1.2	46.0
15th Anniversary of In Service Date	79.5	79.5	1.2	47.2
16th Anniversary of In Service Date	81.1	81.1	1.2	48.1
17th Anniversary of In Service Date	82.3	82.3	1.3	48.9
18th Anniversary of In Service Date	83.2	83.2	1.3	49.4
19th Anniversary of In Service Date	84.0	84.0	1.3	49.9
20th Anniversary of In Service Date	84.9	84.9	1.3	50.4
21st Anniversary of In Service Date	85.6	85.6	1.3	50.8
22nd Anniversary of In Service Date	86.4	86.4	1.3	51.3
23rd Anniversary of In Service Date	87.3	87.3	1.3	51.8
24th Anniversary of In Service Date	88.0	88.0	1.4	52.3
25th Anniversary of In Service Date	88.8	88.8	1.4	52.7

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.78. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

1. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;
(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;
(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
(f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The GST registration number for Hydro One is 87086-5821 RT0001 and the GST registration number for the Customer is as specified in Schedule "A" of the Agreement; and
(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, Connection and operation of the New or Modified Connection Facilities;

(b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(h) Hydro One is not permitted to Connect any new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the *Transmission System Code*, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable

Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Hydro One Connection Work described in Schedule "A", Hydro One shall: provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the *Transmission System Code*, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
(iv) participation in the commissioning, inspection or testing of the Customer's Facilities,

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work ;
(d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the *Transmission System Code*) or a Force Majeure Event;
(e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
(f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998,* such leave is obtained on or before the date specified as the Approval Date in Schedule "A" of the Agreement;
(g) where applicable, Hydro One received the easement described in Section 24 hereof by the Easement Date specified in Schedule "A" of the Agreement;
(h) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Hydro One Connection Work:
    (i) environmental approvals, permits or certificates;
    (ii) land use permits from the Crown; and
    (iii) building permits and site plan approvals;
(j) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on terms substantially similar to the form of the easement that

is attached hereto as Appendix "B" of these Standard Terms and Conditions for the Project, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;

(k) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and

(l) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

6. Upon completion of the Hydro One Connection Work:

(a) Hydro One shall own, operate and maintain all equipment specified in Schedule "A" of the Agreement under the heading "Ownership"; and

(b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit Connection of the New or Modified Connection Facilities to Hydro One's transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

9. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule "B" of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
(iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
(v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
(vi) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contributions paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule "B". If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "B".

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

(a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs;
(b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer; or
(c) the construction of or modifications to Hydro One's Network Facilities that may be required to accommodate the New or Modified Connection other than Network Customer Allocated Work unless Hydro One has indicated in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution.

10.3 Notwithstanding Sub-section 10.2(c) above, if Hydro One indicates in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution towards the Network Pool Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 20 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof and where this Capital Contribution includes the cost of capacity on the Connection Facility not needed by the Customer as indicated in Schedule "B" of the Agreement, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.2.25 of the *Transmission System Code* if that capacity is assigned to another Load Customer within five (5) years of the In Service Date.

11. Hydro One shall perform a True-Up, based on Actual Load:

(a) at the True-Up Points specified in Schedule "A" of the Agreement; and
(b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

(i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

(ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code.*

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code)* during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the Transmission System Code when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14. Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code.*

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1 The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described asWork Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "B" of the Agreement in the manner specified in Schedule "B" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or

(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 18 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the

Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 **Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility:** If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, at least 30 days prior to transferring load from the Existing Load Facility Hydro One will then proceed in accordance with Section 6.7 of the *Transmission System Code*.

17.2 **Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load:** Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One or the OEB, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential by-pass situation in accordance with the OEB-Approved Connection Procedures. If the Customer does not intend to by-pass the Existing Load Facility, the Customer must in accordance with the OEB-Approved Connection Procedures:

i. notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's Existing Load Facility;
ii. transfer the load back to the Existing Load Facility within an agreed time period; and
iii. compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be a term of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or
(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus Taxes) which become payable under this Section 18 within 30 calendar days after the date of invoice.

Part F: Sale, Lease, Transfer or Other Disposition of Customer's Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash, letter of credit or surety bond, the Customer shall furnish such security in the amount and by the dates specified in Schedule "A" of the Agreement. Hydro One shall return the security deposit to the Customer as follows:

(i) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and

(ii) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. Prior to the existence of OEB-Approved Connection Procedures either party may refer a Dispute to the OEB for a determination. Once there are OEB-Approved Connection Procedures, all disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is constructing the New or Modified Connection Facilities, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement.

Part I: Easement

24. If specified in Schedule "A" that an easement(s) is required from the Customer, the Customer shall grant an easement to Hydro One substantially in the form of the easement attached hereto as Appendix "B" of these

Standard Terms and Conditions for the property(ies) described as the Easement Lands in Schedule "A" on or before the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 18 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

(i) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or

(ii) the amounts payable under Section 16 and 18 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms

of this Agreement and the parties shall follow the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the Parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

34. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice shall be deemed to be received on the date of the fax if received before 3 p.m. on a business day or on the next business day if received after 3 p.m. or a day that is not a business day. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

37. The Customer shall provide Hydro One with a copy of the Customer's final monthly bills associated

with the transmission of electricity from the Existing Load Facilities and/or the Customer's Facilities or authorize the IESO to provide Hydro One with same. Hydro One agrees to use this information solely for the purpose of the Agreement.

38. **Invoices and Interest:** Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

39. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 18 or 23 shall survive the termination of the Agreement.

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

"Assigned Capacity" is calculated in accordance with Section 6.2.2 of the *Transmission System* Code.

"Adjusted Load Forecast" means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 5(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code*.

"Connect and Connection" has the same meaning ascribed to the term "Connect" in the *Transmission System Code*.

"Connection Agreement" means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

"Connection Facilities" has the meaning set forth in the *Transmission System Code*.

"Connection Point" has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule "A" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer Connection Risk Classification" is as specified in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer's Facilities.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Dispute" means a dispute between the Parties with respect to any of the matters listed in Section 6.1.4 of the *Transmission System Code* where either Party is alleging that the other is seeking to impose a term that is inconsistent or contrary to the *Ontario Energy Board Act*, the *Electricity Act, 1998*, Hydro One's transmission licence or the *Transmission System Code* or refusing to include a term or condition that is required to give effect to the Code.

"Distributor" has the meaning set forth in the *Transmission System Code*.

"Economic Evaluation Period" means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule "A" of the Agreement.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"*Electricity Act*, 1998" means the *Electricity Act, 1998* being Schedule "A" of the *Energy Competition Act*, S.O. *1998*, c.15, as amended.

"Existing Load" in relation to the Customer and each of the Existing Load Facilities is equal to the Customer's Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

"Existing Load Facility or Existing Load Facilities" means the connection facility(ies) owned by Hydro One as specified in the Existing Load Table in Schedule "A" of the Agreement where the Customer has Existing Load.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"GST" means the Goods and Services Tax.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means Hydro One's structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the *Electricity Act, 1998*.

"In Service Date" has the same meaning ascribed to the term "comes into service" in the *Transmission System Code*.

"Incremental Network Load" means the Customer's New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

"Interest" means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code*.

"Line Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Line Connection Pool Work".

"Line Connection Revenue" means the amount of line connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

"Line Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Load Customer" has the meaning set forth in the *Transmission System Code*.

"Load Forecast" means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Network Customer Allocated Work" means the construction of or modifications to Network Facilities specified in Schedule "A" of the Agreement under the heading "Network Customer Allocated Work" that are minimum connection requirements.

"Network Facilities" has the meaning set forth in the *Transmission System Code*.

"Network Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Network Pool Work".

"Network Revenue" means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

"Network Service Rate" " means the network service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"New Load" means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "A" of the Agreement.

"Normal Capacity" means, where the Customer is:

(a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and
(b) one of two or more Load Customers served by an Existing Load Facility, the Customer's pro-rated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Pool-Funded Cost" means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"**Rate Order"** has the meaning ascribed thereto in the *Transmission System Code*.

"Ready for Service Date" means the date upon which the Hydro One Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Standard Terms and Conditions" means these Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects and Appendices "A" and "B" attached hereto.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"Transformation Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code*.

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code*.

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

Appendix "B": Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of ____
____
____ (the "**Lands**").

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the "**Rights**") in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the "**Strip**") for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the "**Works**") as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the "**obstruction**") whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set his hand and seal to this Agreement, this ___ day of _______ _____________, 200__.

SIGNED, SEALED AND DELIVERED
In the presence of)
) ______________________________________)
______________________________(seal)
Signature of Witness) Transferor's Signature
)
)
)
________________________________) ______________________________(seal)
Signature of Witness Transferor's Signature

)
SIGNED, SEALED AND DELIVERED) Consent Signature & Release of
In the presence of) Transferor's Spouse, if non-owner.
)
)
)
______________________________) ______________________________(seal)
Signature of Witness

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated ____________________

Between ________________________________ and ____

and registered as Instrument Number ___________________ on ______________________________ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name	Signature(s)	Date of Signatures
		Y M D
	Per:	
	________________________________	
	________________________________	
	I/We have authority to bind the Corporation	

Mailing Address:
Hydro One Networks Inc.
483 BAY ST (ACCOUNTS RECEIVABLE UNIT - TCA8)
TORONTO, ON, M5G 2P5

INVOICE

Invoice No.: 3000462465
Customer Ref. No.: N/A
Invoice Date: JUL 09, 2025
Due Date: AUG 08, 2025
Customer No.: 20000146
Payment Terms: Net 30
Interest on Late Payments: 19.56 % per year

BURLINGTON HYDRO INC.
1340 BRANT ST
P.O. BOX 5018
BURLINGTON, ON, L7R 3Z7
CANADA

GST/HST No.: 870865821RT0001

For Billing Enquiries, please call: 1-877-554-7344
Business Hours: 8:00am - 4:00pm Eastern Standard Time

10th Anniversary True-Up of Tremaine TS CCRA | TD Bank, Toronto Swift Code:TDOMCATTTOR Hydro One Inc Account#0690-5202411 Transit#10202-0004 | Please notify FinanceAR@HydroOne.com with payment details and invoice number

Line Item No.	Description	Qty.	Unit Price	TOTAL
1	Transformation Capital Contribution	1.000	63,400.00	63,400.00
	Tremaine TS CCRA CBR00191 - 10th Anniversary True-Up			
	HST 13.00%			8,242.00

Subtotal	63,400.00
HST	8,242.00
TOTAL	$ 71,642.00

Please note: Invoice is subject to Late Payment Interest Charges, if total payment is not received by due date.

<table>
<tr><td colspan="3">Please return this portion with payment or write the complete invoice number on your cheque.</td></tr>
<tr><td>Please send your payment to:

HYDRO ONE NETWORKS INC.
ACCOUNTS RECEIVABLE UNIT - TCA8
483 BAY ST.,
TORONTO, ON, M5G 2P5</td><td>Customer No.: 20000146
Customer Name:
BURLINGTON HYDRO INC.

1340 BRANT ST
P.O. BOX 5018
BURLINGTON, ON, L7R 3Z7
CANADA</td><td>Invoice No: 3000462465
Amount Due: $ 71,642.00
Due Date: AUG 08, 2025
Amount Remitted:

____

Date: ____________________</td></tr>
</table>

Please remit payment directly to address noted above. For payment through Visa/Mastercard, call 1-877-554-7344.
This invoice cannot be paid against your energy account via your financial institution or Internet banking.

Appendix – 2-Staff-28 a)

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro, & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

Prepared by:

Fan Wang
Engineer
Distribution and Asset Management Department

Leslie Greey
Engineer
Distribution and Asset Management Department

Reviewed by:

Katrina Lotho
Engineer
Distribution and Asset Management Department

Approved by:

Yury Tsimberg
Director – Asset Management
Transmission and Distribution Technologies

Dated: December 10, 2009.

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

To: **James Macumber**
Enersource Corporation
3240 Mavis Road
Mississauga, Ontario L5C 3K1

Burlington Hydro
1340 Brant Street,
Burlington, Ontario L7R 3Z7

Oakville Hydro
P.O. Box 1900
861 Redwood Square
Oakville, Ontario L6J 5E3

Halton Hills Hydro
43 Alice Street
Acton, Ontario L7J 2A9

Milton Hydro Distribution Inc.
55 Thompson Road South
Milton, Ontario L9T 6P7

Revision History

Revision Number	Date	Comments	Approved
R000	October 8, 2009	Initial Draft	N/A
R001	October 28, 2009	Finalized Draft (incorporating Consortium's Comments)	N/A
R002	November 23, 2009	Finalized Report (for Consortium's final comments)	N/A
R003	December 10, 2009	Final Version	Y. Tsimberg

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Table of Contents

1 Executive Summary

1.1 Introduction

One of the aspects of switching to International Financial Reporting Standards (IFRS) methodology that Ontario's Local Distribution Companies (LDCs) are embarking upon is trying to align the time period assets are amortized over with their actual useful life.

This is a rather onerous task because LDCs own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Moreover, some assets are comprised of several components that may have differing useful life than the assets themselves. It is therefore important for LDCs to properly account for the useful lives of assets and their components to facilitate conversion to IFRS.

This report reviews the useful lives of the assets, and their components that are applicable to Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro and Milton Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all listed in Section 35 of this Report. Useful lives of assets are dependent on a number of utilization factors (mechanical stress, electrical loading, environmental factors and operating practices) that are described in more detail in Section 1.4 of this report and it is worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

1.2 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by the Consortium members. The typical parent system(s) to which the asset belongs is provided and these "parent" systems are: *Overhead Lines* (OH), *Transmission Stations* (TS), *Municipal Stations* (MS), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism of each asset category is described for each asset category and when applicable assets are sub-categorized into components: components are included when their cost is material enough and, at the same time, component could be replaced without a need to replace the whole asset. For each asset or component, the following information is presented:

- Useful Life Range
- Typical Life
- Typical time-based maintenance intervals, if applicable
- Impact of Utilization Factors

Section 1.4 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

1.3 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by Consortium, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

- The initial list of assets and components was produced by the Consortium members to Kinectrics for review.
- Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.
- The intermediate list was reviewed jointly by the Consortium members and Kinectrics to derive a “final” list.
- For each asset and component in the “final” list, Kinectrics then gathered the information described in Section 1.2 from the sources described in Section 1.1 of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was then produced.
- This Draft Report was reviewed by the Consortium members and their feedback was incorporated in the Final Report.

1.4 Definition of Terms

1.4.1 *Typical Distribution System Asset*

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

1.4.2 *Component*

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

- Its value is significant enough, relative to the asset value.
- A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

1.4.3 *Useful Life*

Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report, the useful life range, in years, is presented in terms of a minimum, maximum, and typical value. An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. An overwhelming majority of the units within this class will perform as required for at least 20 years. Very little number units will operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in Utilization Factors described below.

1.4.4 *Typical Life*

Refers to the typical age at which the asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

1.4.5 *Typical Time-based Maintenance Intervals*

For the purposes of this report, time-based maintenance refers to either *Routine Inspections* (RI) or *Routine Testing/Maintenance* (RTM). Other maintenance techniques such as Condition Based Maintenance, Reliability Centered Maintenance, and more intrusive periodic overhauls are very much dependent on individual utility's maintenance strategy and practices and, as such, could not be included in compiling industry-wide typical values.

Typical time-based maintenance intervals will be given only for assets that are proactively maintained, i.e. assets for which useful life is affected by regular planned maintenance. This excludes assets that are not routinely maintained.

1.4.6 *Impact of Utilization Factors*

For the purpose of this report, stress that impacts the assets refers to *Mechanical Stress* (MC), *Electrical Loading* (EL), *Environmental Conditions* (EN) and/or *Operating Practices* (OP):

- Mechanical stress includes factors such as wind and ice that leads to degradation over time
- Electrical loading refers to either constant loading that creates long term degradation or temporary overloading that may causes a severe degradation
- Environmental conditions include pollution, salt, acid rain, extreme temperature and detrimental animals (i.e. woodpeckers) that may cause degradation over time
- Operating practices refers to how frequently an asset is subject to operating procedure (automatic or manual) that impacts its useful life, e.g. reclosers operations.

Each asset could be impacted by one or more of these factors resulting in a different degradation rates for the same assets and/or components in different jurisdictions. Therefore, it is expected that some of the utility specific typical life values would be different than the ones provided in this report based on the qualitative assessment of the above factors.

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for Consortium assets.

Table 1-1 Summary of Componentized Assets

Report Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life *(years)* Minimum	Typical	Maximum	Maint. Type**	Time Based Maint. Schedule *(years)*	Impact of Stress***	Reference #
2	OH	Wood Poles	Pole		40	44	50	RI	15	MC, EN	[1], [2], [3], [4], [38],[39], [40]
			Cross Arm	Wood	20	40	50				
				Composite	40	60	80				
				Steel	20	70	100				
			Bracket	Galvanized Steel	20	40	50				
			Insulator	Composite	10	20	45				
				Porcelain	40	40	50				
			Anchors & Guying		20	40	50				
3	OH	Concrete Poles	*Refer to Wood Poles (1)*		50	60	60	RI	15	MC, EN	[5], [6]
4	OH	Steel Poles	*Refer to Wood Poles (1)*		60	60	80	RI	15	MC, EN	[7], [8], [41]
5	OH	Composite Poles	*Refer to Wood Poles (1)*		50	70	100	N/A	N/A	MC	[9]

* OH = Overhead Lines TS=Transmission Stations MS=Municipal Stations UG=Underground Systems S=Monitoring & Control System
** RI=Routine Inspection RTM=Routine Testing/Maintenance
*** MC=Mechanical Stress EL=Electrical Loading EN=Environmental Factors OP=Operating Practices

Report Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life *(years)* Minimum	Typical	Maximum	Maint. Type**	Time Based Maint. Schedule *(years)*	Impact of Stress***	Reference #
6	OH	Wires	Conductor	ACSR	50	60	77	N/A	N/A	MC, EL, EN	[5], [10]
				AAC	50	60	77				
				Cu	50	60	77				
				Insulated wire	50	60	77				
			Arrester								
7	OH	Pole Mounted Transformers	Transformer		30	40	60	N/A	N/A	EL, EN	[5]
			Arrester								
8	OH	Manual Overhead Line Switches			30	50	60	RTM	2	EL, EN	[6]
9	OH	Local Motorized Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[6]
			Motor		15	20	20				
10	OH	Remote Automated Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[11], [12]
			Motor		15	20	20				
			RTU		15	20	30				
11	OH	Fuse Cutouts			30	40	60	N/A	N/A	EL, EN	[6]
12	OH	Voltage Regulator			15	20	40	N/A	N/A	EL, EN, OP	[5], [42]

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Section #	Parent*	Asset Category	Componentization (*sub category*)		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
13	OH	Reclosers	Breaker	Vacuum	30	40	40	RTM	10	EL, OP	[5], [6], [11], [12]
				Oil	30	42	60				
			RTU		15	20	30				
14	TS	Station Service Transformers	Dry Type		20	30	40	RTM	3	EL, EN	[1],[13], [45],[46]
			Other		32	45	55				
15	TS	TS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
16	MS	MS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
17	MS	DC Station Service	Battery bank		10	20	30	RTM	1	EL, EN, OP	[6],[17], [18],[19]
			Charger		20	20	30				
18	MS	Air Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				

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** RI=Routine Inspection RTM=Routine Testing/Maintenance
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Section #	Parent*	Asset Category	Componentization (*sub category*)		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
19	MS	Gas Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				
20	MS	Building	Building		30	50	80	RI	1	MC, EN	[13]
			Roof		15	20	20				
			Fence		30	35	45				
21	MS	Station Grounding System			25	40	50	N/A	N/A	EN	[13],[22], [23]
22	UG	UG Primary Cables	TR-XLPE	In Duct	40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
				In Concrete Encased Duct	40	40	60				
				Direct Buried	20	25	40				
			Termination		25	40	60				
			Arrester								
23	UG	UG Secondary Cables	PI (polyethylene insulated)		40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
			PIJ (PVC jacket)		40	40	60				

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** RI=Routine Inspection RTM=Routine Testing/Maintenance
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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
24	UG	Distribution Transformer	Transformer	Pad Mounted	30	40	40	N/A	N/A	EL, EN, OP	[5],[4], [6]
				Vault	30	40	40				
				Submersible	25	35	40				
			Elbows and Inserts		20	40	60				
25	UG	Pad Mounted Switchgear	Air Insulated		20	30	40	RI	3	EL, EN, OP	[26],[27], [28]
			Gas Insulated		30	30	50				
			Solid Dielectric		30	30	50				
26	UG	Vault Switch	Metal Enclosed Switch		20	30	40	RI	3	EL, EN, OP	[6],[26], [27]
			Metal Enclosed Cutout		30	40	60				
27	UG	Utility Chamber			50	60	80	RTM	3	EN	[5],[6], [29]
28	UG	Duct	Duct Bank		30	50	80	N/A	N/A	EN	[5],[6], [30]
			Direct Buried Pipe (PVC)		30	50	75				
			HDPE		50	50	100				
29	UG	Transformer and Switchgear Foundations			30	60	80	RTM	3	EN	[5],[6]
30	UG	Junction Cubicle			25	40	50	N/A	N/A	EN	[5]
31	S	"Classic" SCADA	RTU		15	20	30	N/A	N/A	OP	[1],[11], [12],[32]
			Relay		20	30	50				
			Battery		5	10	10				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
32	S	IED Based SCADA	IED		10	15	15	N/A	N/A	OP	[13],[32], [33]
			Battery		5	10	20				
33	S	Fault Indicators	Overhead		5	10	20	N/A	N/A	EN	[34], [47]
			Underground		10	20	30				
34	S	Metering	Meter	Residential	20	30	45	N/A	N/A	EN	[5],[35], [36]
				Industrial	20	30	60				
				Wholesale	20	30	60				
			CT		30	45	50				
			PT		30	45	50				
35	S	Smart Metering	Smart Meter		15	15	20	N/A	N/A	EN	[5],[37]
			Repeaters		5	10	15				
			Antennas								
			Data Concentrator	Sockets & Poles	10	20	20				
			Powerline Repeaters		5	10	15				
			Sky Pilot Devices								
			WAN Equipment								

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** RI=Routine Inspection RTM=Routine Testing/Maintenance
*** MC=Mechanical Stress EL=Electrical Loading EN=Environmental Factors OP=Operating Practices

2 Wood Poles

The asset referred to in this category is the fully dressed wood pole ranging in size from 30 to 75 feet. This includes the wood pole, cross arm, bracket, insulator, and anchor & guys. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines.

The most significant component of this asset is the wood pole itself. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

2.1 Degradation Mechanism

The end of life criteria for wood poles includes loss of strength, functionality, or safety (typically due to rot, decay, or physical damage). As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

2.2 System Hierarchy

Wood poles are considered to be a part of the Overhead Lines asset grouping.

2.3 Useful Life and Typical Life

The overall useful life of a wood pole is in the range of 40 to 50 years; the typical life is 44 years.

This asset also has several major components, each with a different useful life:

- Cross Arm (Wood, Composite, Steel)
- Bracket (Galvanized Steel)
- Insulator (Composite, Porcelain)
- Anchor and Guying

2.3.1 *Cross Arm*

The useful life of a <u>wood</u> cross arm is in the range of 20 to 50 years; the typical life is 40 years.

The useful life of a composite cross arm is in the range of 40 to 80 years; the typical life is 60 years.

The useful life of a steel cross arm is in the range of 20 to 100 years; the typical life is 70 years.

2.3.2 *Bracket (Galvanized Steel)*

The useful life of an aluminum bracket component ranges from 20 to 50 years, with a typical value of approximately 40 years.

2.3.3 *Insulator*

The useful life of a composite insulator is in the range of 10 to 45 years; the typical life is 20 years.

The useful life of a porcelain insulator is in the range of 40 to 50 years, with a typical life of 40 years.

2.3.4 *Anchors and Guying*

The useful life of anchors and guying is in the range of 20 to 50 years; the typical life is 40 years.

2.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

2.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

3 Concrete Poles

This asset category includes the concrete pole with the same components as for the wood poles, namely cross arm, bracket, insulator, and anchor. These poles range in size from 35 to 80 feet, with the typical pole being 60 feet.

3.1 Degradation Mechanism

The most significant component in this class is the concrete pole itself. Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in), however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice, resulting in cracking and separation of the concrete. The spun concrete process used in manufacturing poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

3.2 System Hierarchy

Concrete poles are considered to be a part of the Overhead Lines assets grouping.

3.3 Useful Life and Typical Life

The useful life range of the concrete pole component is 50 to 60 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

3.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

3.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

4 Steel Poles

This asset category includes the directly buried steel pole, cross arm, bracket, insulator, and anchor.

4.1 Degradation Mechanism

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground. In-ground situations are vastly different because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground.

There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations.

Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

4.2 System Hierarchy

Steel poles are considered a part of the Overhead Lines asset grouping.

4.3 Useful Life and Typical Life

The useful life of steel poles is in the range of 60 to 80 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

4.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

4.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

5 Composite Poles

This asset category includes the composite pole, cross arm, bracket, insulator, and anchor. At Consortium the composite poles are fiberglass.

5.1 Degradation Mechanism

The most significant component in this class is the composite pole itself. The major degradation of composite poles is ultra violet (UV) degradation. It represents an attack from ultra-violet radiation, which might result in crack or disintegration in composite poles. It is a common problem in products exposed to sunlight. Continuous exposure is a more serious problem than intermittent exposure, since attack is dependent on the extent and degree of exposure. In fiber products like composite poles, useful life will be shortened because the outer fibers will be attacked first, and will easily be damaged by abrasion. This will end up with fiber blooming and fading.

5.2 System Hierarchy

Composite poles are considered to be a part of the Overhead Lines assets grouping.

5.3 Useful Life and Typical Life

The useful life range of the composite pole component is 50 to 100 years; the typical life is 70 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

5.4 Time Based Maintenance Intervals

. Composite poles are not subject to planned maintenance.

5.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress.

6 Wires

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, and insulated wire.

6.1 Degradation Mechanism

To function properly, conductors must retain both their conductive properties and mechanical (i.e. tensile) strength. Aluminum conductors have three primary modes of degradation: corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation.

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

Fatigue degradation presents greater detection and assessment challenges than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes. However, under normal operating conditions, with proper design and application of vibration control, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases detectable indications of fatigue may only exist during the last 10% of a conductor's life.

In designing transmission lines, engineers ensure that conductors receive no more than 60% of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor's RTS, significant sag occurs, requiring either resagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

6.2 System Hierarchy

The Wire asset category belongs to the Overhead Lines assets grouping.

6.3 Useful Life and Typical Life

The useful life of conductors is in the range of 50 to 77 years; the typical life is 60 years.

6.4 Time Based Maintenance Intervals

Overhead conductors are not subject to planned maintenance.

6.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress, Electrical Loading and Environmental Conditions.

7 Pole Mounted Transformers

Distribution pole top mounted transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

7.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

7.2 System Hierarchy

The Pole Mounted Transformer asset category belongs to the Overhead Lines assets grouping.

7.3 Useful Life and Typical Life

The useful life of the pole mounted transformer is in the range of 30 to 60 years, with a typical value close to 40 years.

7.4 Time Based Maintenance Intervals

Pole mounted distribution transformers are not subject to planned maintenance.

7.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

8 Manual Overhead Line Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

8.1 Degradation Mechanism

The main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

8.2 System Hierarchy

Overhead Switches asset category belongs to the Overhead Lines assets grouping.

8.3 Useful Life and Typical Life

The useful life of manually operated switches is in the range of 30 to 60 years; the typical life is 50 years.

8.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for manually operated overhead switches is two years.

8.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

9 Local Motorized Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches and a motor. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism is controlled by a motor.

9.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with local motorized overhead switches include the following:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of degradation are a function on operating duties and environment.

9.2 System Hierarchy

Local Motorized Overhead Switches category belongs to the Overhead Lines assets grouping.

9.3 Useful Life and Typical Life

The local motorized overhead switch can be componentized into two components:

- Switch
- Motor

9.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead switch in section 8.3 of this report).

9.3.2 *Motor*

The useful life of the motor of local motorized switches is in the range of 15 to 20 years; the typical life is about 20 years.

9.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for local motorized switches is every two years.

9 Local Motorized Overhead Line Switches

9.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

10 Remote Automated Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions and operate only when the current through the switch is zero. Most distribution line switches are rated 600 to 900 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in open position. This component also consists of a remote terminal unit (RTU) component.

10.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

10.2 System Hierarchy

Remote Automated Overhead switches asset category belongs to the Overhead Lines assets grouping.

10.3 Useful Life and Typical Life

The remote automated overhead switch can be componentized into three components:

- Switch
- Motor
- Remote Terminal Unit (RTU)

10.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead Switch in section 8.3 of this report).

10.3.2 *Motor*

The useful life of a motor is in the range of 15 to 20 years; the typical life is 20 years (the same as for Local Motorized Overhead Switch in section 9.3.2 of this report).

10.3.3 *Remote Terminal Unit (RTU)*

The useful life of an RTU is in the range of 15 to 30 years; the typical life is 20 years.

10.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for remote automated overhead switches is every two years.

10.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

11 Fuse Cutouts

This asset is applied on overhead transformers, capacitors, cables or lines. Fuse Cutouts will interrupt all faults including low current that will melt the fuse link and high rated interrupting current so long as the system is under realistic transient-recovery-voltage conditions.

11.1 Degradation Mechanism

The major degradation of fuse cutouts is on fuse body. There are several degradation modes in practice including the production of carbon from organic materials in the fuse, generation of water vapor to assist current interruption and electrical breakdown in high stress areas of the core.

The production of carbon from organic materials in the fuse body is one degradation mode in practice. This carbon is not produced until a particular body temperature is reached, and the time for this to occur depends on the fuse design. The most critical factors would appear to include the heat generated in the fulgurite, the distance between the fulgurite and the fuse body, the thermal conductivity of the filler material, and the breakdown temperature of the organic material.

For some fuses that generate water vapor to assist current interruption, the water is deposited on the inside surface of the body. Treeing is observed on the surface, ultimately leading to a steady increase in leakage current until failure.

For the fuse cores that contain organic material, hollow core is developed at high temperature due to release of water molecules, resulting in electrical breakdown in high stress areas of the core in certain designs.

11.2 System Hierarchy

Fuse Cutouts asset category belongs to the Overhead Lines assets grouping.

11.3 Useful Life and Typical Life

The useful life of fuse cutouts is in the range of 30 to 60 years; the typical life is 40 years.

11.4 Time Based Maintenance Intervals

Fuse Cutouts are not subject to planned maintenance

11.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

12 Voltage Regulators

Voltage regulators are static devices that perform step-up and step-down voltage change operations. Distribution line transformers change the medium or low distribution voltage to 120/240 V or other common voltages for use in residential and commercial applications.

12.1 Degradation Mechanism

It has been demonstrated that the life of the voltage regulator's internal insulation is related to temperature-rise and duration. Therefore, voltage regulator life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of voltage regulators.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of voltage regulator that should be selected for a given number and type of customers to obtain optimal life. There is also the operating practices affect on voltage regulators. If it is a strong system, the voltage regulator may not need to step-up or step-down the voltage, in which case there would be less stress on the device itself.

12.2 System Hierarchy

Voltage Regulators asset category belongs to the Overhead Lines assets grouping.

12.3 Useful Life and Typical Life

The useful life of voltage regulators is in the range of 15 to 40 years; the typical life is 20 years.

12.4 Time Based Maintenance Intervals

Voltage Regulators are not subject to planned maintenance.

12.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

13 Reclosers

This asset class consists of light duty circuit breakers equipped with interrupters that use controllers. This is where the breaking and making of fault current takes place. The interrupters use oil of vacuum as the insulating agent. The controllers are either hydraulic or electric. It is designed for single phase or three phase use, depending on the model.

13.1 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect suppression devices as well as the contacts, the oil, and the arc control. The degradation of these devices depends on the prevailing fault, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism mal-function. For deterioration, exposure to weather is a potentially significant degradation process – primarily corrosion of the tank and other metallic components and deterioration of bushings.

13.2 System Hierarchy

Recloser asset category belongs to the Overhead Lines assets grouping.

13.3 Useful Life and Typical Life

Reclosers can be categorized into two components:

- Breaker (Vacuum, Oil)
- RTU

13.3.1 *Breaker*

The useful life of Vacuum breakers is in the range of 30 to 40 years; the typical life is 40 years.

The useful life of Oil breakers is in the range of 30 to 60 years; the typical life is 42 years.

13.3.2 *RTU*

The useful life of recloser RTUs is in the range of 15 to 30 years; the typical life is 20 years.

13.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for the breaker component of reclosers is every ten years.

13.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Operating Practices.

14 Station Service Transformers

The station service transformers are the small transformers are configured to provide power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. This report refers to both to both dry type and other types of transformers.

14.1 Degradation Mechanism

As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

For dry type transformers, the major degradation factors are dirt and moisture. Dirt will contaminate insulation surfaces allowing the formation of conductive paths along the surfaces and eventually to ground. In the case of ventilated dry type transformers, the windings are in direct contact with the air. External air-carrying contaminants or excessive moisture could reduce winding insulation. Dust and dirt accumulation can also reduce air circulation through windings, which eventually shorten the life expectancy of a dry type transformer.

14.2 System Hierarchy

Station service transformers are considered part of the Transmission Stations assets grouping.

14.3 Useful Life and Typical Life

The useful life of a station service transformer is based on the transformer type:

- Dry Type
- Other

14.3.1 *Dry Type*

The useful life of dry type station service transformers is in the range of 20 to 40 years; the typical life is 30 years.

14.3.2 *Other*

The useful life of other station service transformers is in the range of 32 to 55 years; the typical life is 45 years.

14.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is three years.

14.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions. If this device is running within an electrically stable system there will be less stress imposed on it.

15 TS Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA. The Consortium typically uses TS Power Transformers rated 75/125 MVA.

15.1 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

15.2 System Hierarchy

Power Transformers belong to the Transformer Stations assets grouping.

15.3 Useful Life and Typical Life

This asset could be componentized into the following components:

- Winding
- Manual/Automatic On Load Tap Changer

15.3.1 *Winding*

The useful life of the winding can be in the range of 32-55 years, depending on the loading condition and ambient operating temperature, and routine maintenance practices. A typical life of 45 years can be expected for the winding system.

15.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic on load tap changer, assuming it is vacuum type, is 20-60 years; the typical life is 20 years.

15.4 Time Based Maintenance Intervals

For TS power transformers, the typical routine testing/maintenance interval is two years.

15.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

16 MS Power Transformers

Power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA. The Consortium typically uses MS Power Transformers rated 20/33.3 MVA.

16.1 Degradation Mechanism

The degradation of the power transformers at municipal stations or at customer sites is similar to that of the transformers at transmission stations. These transformers are subject to electrical, thermal, and mechanical aging. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

16.2 System Hierarchy

MS Power Transformer asset category belongs to the Municipal Stations assets grouping.

16.3 Useful Life and Typical Life

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Winding
- Manual/Automatic On Load Tap Changer

16.3.1 *Winding*

The useful life of windings is 32 to 55 years; the typical life is 45 years.

16.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic tap changer, assuming it is vacuum type, is 20 to 60 years; the typical life is 20 years.

16.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

16.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically sound system there will be less stress imposed on it.

17 DC Station Service

The DC station service asset class includes battery banks and chargers. Equipment within transmission and municipal stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power so the only guaranteed instantaneous power source must be DC, based on batteries.

17.1 Degradation Mechanism

Effective battery life tends to be much shorter than many of the major components in a station. The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service are still relatively frequent. For this reason, many utilities employ battery monitors and alarm systems. The earlier versions of these are still widely used and are relatively unsophisticated devices that measure basic battery parameters with pre-set alarm levels. More modern monitoring devices have the ability to identify a potential failure as it develops and to provide a warning.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves. Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

17.2 System Hierarchy

DC station services belong to Municipal Stations assets grouping.

17.3 Useful Life and Typical Life

This asset also has two major components that have differing useful lives:

- Battery Banks
- Charger

17.3.1 *Battery Bank*

The battery bank has a useful life range of 10 to 30 years; typical life is 20 years.

17.3.2 *Charger*

The charger has a useful life range of 20 to 30 years; typical life is 20 years.

17.4 Time Based Maintenance Intervals

Typically, routine testing/maintenance for batteries are conducted annually. The maintenance of schedule battery chargers is typically coordinated with that of the battery.

17.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. This device cannot be overloaded, last longer when there is not extreme cold weather conditions and only the battery bank component is affected by operating practices (i.e., it only runs if the AC fails).

18 Air Insulated Switchgear

Air Insulated Switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium voltage range, from 4.16 to 44 kV. The switchgear includes breakers; disconnect switches, or fusegear, current transformers (CTs), voltage transformers (VTs) and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The gear is modular in that each breaker is enclosed in its own metal envelope (cell). The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

18.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Correct operation of the mechanism is critical in devices that make or break fault currents, i.e. the contact opening and closing characteristics must be within specified limits. The greatest cause of mal-operation of switchgear is related to mechanism malfunction. Deterioration due to corrosion or wear due to lubrication failure may compromise mechanism performance by either preventing or slowing down the operation of the breaker. This is a serious issue for all types of switchgear.

In older air filled equipment, degradation of active solid insulation (for example drive links) has been a significant problem for some types of switchgear. Some of the materials used in this equipment, particularly those manufactured using cellulose-based materials (pressboard, SRBP, laminated wood) are susceptible to moisture absorption. This results in a degradation of their dielectric properties that can result in thermal runaway or dielectric breakdown. An increasingly significant area of solid insulation degradation relates to the use of more modern polymeric insulation. Polymeric materials, which are now widely used in switchgear, are very susceptible to discharge damage. These electrical stresses must be controlled to prevent any discharge activity in the vicinity of polymeric material. Failures of relatively new switchgear due to discharge damage and breakdown of polymeric insulation have been relatively common over the past 15 years.

Temperature, humidity and air pollution are also significant degradation factors, so indoor units tend to have better long-term performance. The safe and efficient operation of switchgear and its longevity may all be significantly compromised if the substation environment is not adequately controlled. In addition, the air switchgear can tolerate less number of full fault operations before maintenance is required.

18.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

18.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

18.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

18.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

18.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

18.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

19 Gas Insulated Switchgear

The latest design of metalclad gear is the Gas Insulated Switchgear (GIS), which uses low-pressure SF6 gas as a general insulation medium, as a replacement for the air. The insulation within the metal enclosure is not necessarily the same as the working fluid in the breakers themselves, which presently is either SF6 or vacuum.

19.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Generally, mechanism malfunction causes most operational problems in GIS. Corrosion and lubrication failure may compromise mechanism performance by preventing or slowing its operation.

Solid insulation such as that in entrance bushings, internal support insulators, plus breaker and switch operating rods have caused many GIS failures. Manufacturing, shipping, installing, maintaining and operating the GIS can cause defects in the insulation. Defects include voids in epoxy insulators, delamination of epoxy and metallic hardware, and protrusions on conductors. In floating components, fixed and moving particles can lead to failures. Partial discharge (PD) activity usually leads to flashovers.

Corrosion and general deterioration increase risks of moisture ingress and SF6 leaks, particularly in outdoor GIS. If not treated, these factors may cause the end-of-life for GIS.

GIS is designed and manufactured for outdoor use, but it generally has better long-term performance when installed indoors. Outdoor GIS, particularly older ITE designs, have higher than acceptable SF6 gas leaks because of the poor quality of fittings, connectors, valves, by-pass piping, general enclosure porosity and flange corrosion. Indoor installations reduce problems from corrosion, moisture ingress, low ambient temperatures and SF6 leaks.

GIS have more costly, difficult and time-consuming post fault maintenance requirements than air insulated switchgear. Older GIS have even more post-fault maintenance problems. Accessibility, fault location, fault level and duration, degree of compartmentalization, isolation requirements, pressure relief, burn-through protection, parts and service capabilities all help determine post-fault maintenance needs.

19.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

19.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

19.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

19.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

19.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

19.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

20 Building

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building itself (foundations, walls), roof, and fence.

20.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings. It is the potential water ingress with poses the most danger to the asset due to the presence of electrical equipment. In order to prevent this, the buildings must be weatherproof.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

20.2 System Hierarchy

Building asset category belongs to the Municipal Stations assets grouping.

20.3 Useful Life and Typical Life

The overall useful life range of the building itself is 30 to 80 years; the typical life is 50 years.

This asset also has two other major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Roof
- Fence

20.3.1 *Roof*

The useful life of the roof can be in the range of 15 to 20 years, with a typical life of 20 years.

20.3.2 *Fence*

The useful life range of the fence is 30 to 45 years, with a typical life of 35 years.

20.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is every year.

20.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

21 Station Grounding System

The station grounding system asset refers to grounding rods and connectors. Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system.

21.1 Degradation Mechanism

Station grounding systems keep ground potential rise, step and touch potentials below specified limits when maximum (i.e. worst case) ground faults occur. Under fault conditions, the following factors determine step and touch potentials:

- Magnitude of the fault current
- Resistance of ground combined with the ground grid consisting of station electrodes, transmission line sky wires and distribution neutrals
- Ground resistivity of upper and lower layers of earth.

Increases in system capacity and fault currents at a station may lead to unacceptable performance of the ground grid. Corrosion of buried conductors and connectors, mechanical damage to buried electrodes, plus burning-off of grounding conductors and connectors during heavy fault currents also may lead to unsatisfactory performance. Further, changes in resistivity of upper or lower layers of earth may adversely affect ground grid characteristics.

21.2 System Hierarchy

Station Grounding Systems asset category belongs to the Municipal Stations assets groupings.

21.3 Useful Life and Typical Life

Station grounding systems have a useful life range of 25 to 50 years; the typical life is 40 years.

21.4 Time Based Maintenance Intervals

Station Grounding Systems are not subject to planned maintenance.

21.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

22 Underground Primary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The initial capital cost of a distribution underground cable circuit is three or more times the cost of an overhead line of equivalent capacity and voltage. The cross linked polyethylene (XLPE) cable is the type of underground distribution cables used by Consortium. While XLPE underground cable can be installed in ducts (and concrete enclosed ducts), it can also be directly buried.

Cable terminations are designed to separate the cable ground from the conductor in a safe and controlled manner. Inside the cable, ground and high voltage are separated by only a few millimeters. This distance is much too small to support any voltage. Therefore the termination must increase this separation while being able to withstand the surrounding environment.

22.1 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early polymeric cables. As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved.

The major degradation problems with the cable terminations concern mostly flashover and tracking associated with the outside and interior surfaces of the accessory. However, there are also problems of overheating at connections and voltage control at the end of the cable shield.

22.2 System Hierarchy

Underground Primary Cables asset category belongs to the Underground Systems assets grouping.

22.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type and component:

- TR-XLPE (In Duct, In Concrete Encased Duct, Direct Buried)
- Termination

22.3.1 *TR-XLPE*

The useful life range of in duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of in concrete encased duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of direct buried cable is 20 to 40 years; the typical life is 25 years.

22.3.2 *Termination*

The useful life range of termination component of underground cable is 25 to 60 years; the typical life is 40 years.

22.4 Time Based Maintenance Intervals

Underground Primary Cables are not subject to planned maintenance.

22.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

23 Underground Secondary Cables

Secondary underground cables are used to supply customer premises. The Polyethylene Insulated (PI) and PVC Jacket (PIJ) are similar to the XLPE cables described above, and are assumed to be in duct.

23.1 Degradation Mechanism

Underground secondary conductors are typically insulated with polyethylene. Polyethylene insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. These commissioning tests are an area of some concern for polyethylene cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables. However those with the PVC jacket have further insulation to prevent some deterioration of the insulation.

23.2 System Hierarchy

Underground Secondary Cables are used in the Underground system.

23.3 Useful Life and Typical Life

The underground secondary cable can be categorized into two types:

- Polyethylene Insulated
- PVC Jacket

23.3.1 *Polyethylene Insulated*

The useful life range of in polyethylene insulated cable is 40 to 60 years; the average life is 40 years.

23.3.2 *PVC Jacket*

The useful life range of in PVC jacket cable is 40 to 60 years; the average life is 40 years.

23.4 Time Based Maintenance Intervals

Underground Secondary Cables are not subject to planned maintenance

23.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

24 Distribution Transformer

This asset class consists of the transformer and elbows and inserts associated with the system. There are three types of transformers that Consortium uses: Pad Mounted, Vault and Submersible.

Pad mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. Vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil. Submersible transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

24.1 Degradation Mechanism

The pad-mounted transformer has a similar degradation mechanism to other distribution transformers. It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

The vault transformer and submersible transformer have a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

24.2 System Hierarchy

Distribution Transformers asset category belongs to the Underground Systems asset grouping.

24.3 Useful Life and Typical Life

The overall useful life range of the transformer itself is dependent on the component:

- Transformer (Pad Mounted, Vault, Submersible)
- Elbows and Inserts

24.3.1 *Transformer*

The useful life range of pad mounted distribution transformers are 30 to 40 years; the typical life is 40 years.

The useful life range of vault distribution transformers is 30 to 40 years; the typical life is 40 years.

The useful life range of submersible distribution transformers is 25 to 40 years; the typical life is 35 years.

24.3.2 *Elbows and Inserts*

The useful life range of the elbows and inserts component of distribution transformers is 20 to 60 years; the typical life is 40 years.

24.4 Time Based Maintenance Intervals

Distribution Transformers are not subject to planned maintenance.

24.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. The operating practices impact only the elbows and inserts component of the asset.

25 Pad Mounted Switchgear

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 load break switches and vacuum fault interrupters. A majority of the pad mounted switchgear currently employs air-insulated gang operated load-break switches.

25.1 Degradation Mechanism

The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

25.2 System Hierarchy

Pad-Mounted Switchgear belongs to the Underground Systems assets grouping.

25.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the pad mount switchgear type:

- Air Insulated
- Gas Insulated
- Solid Dielectric

25.3.1 *Air Insulated*

The useful life range of this air insulated pad mount switchgear is 20 to 40 years; the typical life is 30 years.

25.3.2 *Gas Insulated*

The useful life range of this gas insulated pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.3.3 *Solid Dielectric*

The useful life range of this solid dielectric pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is three years.

25.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

26 Vault Switch

The vault switches used by Consortium are metal enclosed switch and metal enclosed cutout. These units are essentially pad mounted switchgear, enclosed in stainless steel containers, with the ability to be wall or ceiling mounted.

26.1 Degradation Mechanism

The degradation mechanism of this asset is similar to that of other types of pad mounted switchgear. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

26.2 System Hierarchy

Vault Switches asset category belongs to the Underground Systems assets grouping.

26.3 Useful Life and Typical Life

The overall useful life range of the vault switch is dependent on the pad mount switchgear type:

- Metal Enclosed Switch
- Metal Enclosed Cutout

26.3.1 *Metal Enclosed Switch*

The useful life range of metal enclosed switch is 20 to 40 years; the typical life is 30 years.

26.3.2 *Metal Enclosed Cutout*

The useful life range of metal enclosed cutout is 30 to 60 years; the typical life is 40 years.

26.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is 3 years.

26.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

27 Utility Chamber

Utility Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

27.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, utility chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Utility chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Utility chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a utility chamber system. Similarly, utility chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with utility chambers also requires evaluation in assessing the overall condition of a utility chamber system.

27.2 System Hierarchy

Utility Chambers asset category belongs to the Underground Systems assets grouping.

27.3 Useful Life and Typical Life

Utility chambers have a useful life range of 50 to 80 years; the typical life range is 60 years.

27.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

27.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

28 Duct

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually two to six inches in diameter.

28.1 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

28.2 System Hierarchy

Ducts asset category belongs to the Underground Systems assets grouping.

28.3 Useful Life and Typical Life

The overall useful life range of the duct is dependent on the type:

- Duct Bank
- Direct Buried Pipe (PVC)
- High Density Polyethylene (HDPE)

28.3.1 *Duct Bank*

The useful life range of the duct bank type is 30 to 80 years; the typical life is 50 years.

28.3.2 *Direct Buried Pipe (PVC)*

The useful life range of the direct buried pipe type is 30 to 75 years; the typical life is 50 years.

28.3.3 *High Density Polyethylene (HDPE)*

The useful life range of the HDPE type is 50 to 100 years; the typical life is 50 years.

28.4 Time Based Maintenance Intervals

Ducts are not subject to planned maintenance.

28.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

29 Transformer and Switchgear Foundations

This asset class is similar to the utility chamber asset. It is a buried pre cast concrete vault on which pad-mounted transformers or switchgear are mounted. The foundation itself is buried; however the top portion is above ground.

29.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, transformer and switchgear foundation must withstand heavy loads associated with traffic in the boulevard. When located in driving lanes, concrete vault must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Transformer and switchgear foundation degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Transformer and switchgear foundation also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a transformer and switchgear foundation. Similarly, transformer and switchgear foundation with lights that do not function properly constitute defective systems.

29.2 System Hierarchy

Transformer and Switchgear foundations asset category belongs to the Underground Systems assets grouping.

29.3 Useful Life and Typical Life

The overall useful life range of Transformer and switchgear foundation is 30 to 80 years; the typical life is 60 years.

29.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

29.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

30 Junction Cubicle

This asset class consists of a wiring box similar to pad mount switchgear. For the purposes of this study there is only reference to junction casing.

30.1 Degradation Mechanism

The main degradation associated with the junction cubicle casing is caused by outside sources. These include corrosion, vehicle damage, case rusting, and dirt or contamination.

30.2 System Hierarchy

Junction cubicle is used in the Underground Systems assets grouping.

30.3 Useful Life and Typical Life

The overall useful life range of junction cubicle casing is 25 to 50 years; the typical life is 40 years.

30.4 Time Based Maintenance Intervals

Junction Cubicles are not subject to planned maintenance

30.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

31 “Classic” SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

31.1 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

31.2 System Hierarchy

Classic SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

31.3 Useful Life and Typical Life

This asset has several major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- RTU
- Relay
- Battery

31.3.1 *RTU*

The useful life of the RTU in “classic” SCADA is in the range of 15 to 30 years; the typical life is 20 years.

31.3.2 *Relay*

The useful life of the relay in “classic” SCADA is in the range of 20 to 50 years; the typical life is 30 years.

31.3.3 *Battery*

The useful life of the battery in “classic” SCADA is in the range of 5 to 10 years; the typical life is 10 years.

31 “Classic” SCADA

31.4 Time Based Maintenance Intervals

“Classic” SCADA is not subject to planned maintenance.

31.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery and relay components that are affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

32 IED Based SCADA

Intelligent Electronic Devices (IED) based Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility.

32.1 Degradation Mechanism

Physical degradation of IED Based SCADA happens on hardware part of an IED. Compared to solid state relays, IEDs are not sensitive to ambient environment. The major contributing factor of degradation is the electrical environment, i.e. inrush transient. Since IEDs have built-in self-supervision system, the settings with perfect long time stability is guaranteed.

The failure mode of an IED can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Mal-function due to software design flaw causing software latched by external EMI interference
- Will not operate due to power supply failure

To assess the health status of an IED, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., overcurrent, distance etc.)
- Reliability, including mal-operation count, loading and age

32.2 System Hierarchy

IED Based SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

32.3 Useful Life and Typical Life

This asset has two major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- IED
- Battery

32.3.1 *IED*

The useful life of the IED in IED based SCADA is in the range of 10 to 15 years; the typical life is 15 years.

32.3.2 *Battery*

The useful life of the battery in IED based SCADA is in the range of 5 to 20 years; the typical life is 10 years.

32.4 Time Based Maintenance Intervals

IED based SCADA is not subject to planned maintenance.

32.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

33 Fault Indicators

Fault indicators are used for loaded underground distribution circuits where secondary voltage is available - pad mounted transformers, switchgear and underground vault applications. A sensor monitors the line current. When the trip rating is exceeded, the indicator trips to the fault position. To reset the display the fault indicator uses a secondary voltage source, such as the low-voltage terminals of distribution transformers.

33.1 Degradation Mechanism

Fault indicators have durable Lexan housings, and utilize coated nickel iron sensor laminations encapsulated in a polyurethane potting compound for environmental protection. Overhead fault indicators use batteries, hence their useful life is based primarily on the end of life of the battery itself. The useful life of overhead fault indicators is significantly less than underground fault indicators due to this battery component.

33.2 System Hierarchy

Fault Indicators asset category belongs to the Monitoring and Control Systems assets grouping.

33.3 Useful Life and Typical Life

The overall useful life range of the fault indicator itself is dependent on the type:

- Overhead
- Underground

33.3.1 *Overhead*

The useful life of the overhead fault indicator is based on the useful life of its battery which is in the range of 5 to 20years; the typical life is 10 years.

33.3.2 *Underground*

The useful life of the underground fault indicator is in the range of 10 to 30 years; the typical life is 20 years.

33.4 Time Based Maintenance Intervals

Fault Indicators are not subject to planned maintenance.

33.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

34 Metering

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on those meters used for residential meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT).

34.1 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

34.2 System Hierarchy

Metering asset category belongs to the Monitoring and Control Systems assets grouping.

34.3 Useful Life and Typical Life

There are two components of the meter which have their own useful and typical life:

- Meter (Residential, Industrial/Commercial, Wholesale)
- Transformer (Current, Potential)

34.3.1 *Meter*

The useful life range of residential type meter is 20 to 45 years; typical life is 30 years.

The useful life range of industrial/commercial type meter is 20 to 60 years; typical life is 30 years.

The useful life range of wholesale type meter is 20 to 60 years; typical life is 30 years.

34.3.2 *Transformer (Current, Potential)*

The useful life range of the CT component is 30 to 50 years; typical life is 45 years.

The useful life range of the PT component is 30 to 50 years; typical life is 45 years.

34.4 Time Based Maintenance Intervals

Meters are not subject to planned maintenance

34.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

35 Smart Metering

A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

35.1 Degradation Mechanism

The major degradation mechanism of smart metering system is listed as follows:

- Wiring insulation deterioration due to corrosion, moisture or overheating
- Poor electrical connections due to corrosion, vibration or other physical problems
- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

Typically, terminations and connectors experience mechanical degradation. In damp locations it is common for verdigris, which is the green coating or patina formed when copper, brass or bronze is weathered and exposed to air or seawater over a period of time, to form. Typical problems for these components include:

- Failed crimped terminations due to movement
- Cracked terminal blocks
- Stripped threads
- Mechanical damage from over tightening

Typical degradation processes for the cabinets or racks include:

- Corrosion
- Loss of mechanical strength through use (e.g. swing front panels)

Microwave electronics in smart metering system range from capacitors and resistors to solid-state printed circuit boards. All electronic components have finite lifetimes. Modern highly integrated electronic equipment consists of application specific integrated circuits, surface mounted components, and multi-layer boards.

35.2 System Hierarchy

Smart Metering asset category belongs to the Monitoring and Control Systems assets grouping.

35.3 Useful Life and Typical Life

There are several components of the smart meter which have their own useful and typical life:

- Smart Meter
- Repeater
- Data Concentrator
- Powerline Repeaters

35.3.1 *Smart Meter*

The useful life range of the smart meter is 15 to 20 years; typical life is 15 years.

35.3.2 *Repeater*

The useful life range of the repeater is 5 to 15 years; typical life is 10 years.

35.3.3 *Data Concentrator*

The useful life range of the data concentrator is 10 to 20 years; typical life is 20 years.

35.3.4 *Powerline Repeaters*

The useful life range of the powerline repeater is 5 to 15 years; typical life is 10 years.

35.4 Time Based Maintenance Intervals

Smart Meters are not subject to planned maintenance

35.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2024-12-31

For more information, see the section called "Capital Cost Allowance" in Guide T4012, *T2 Corporation – Income Tax*.

Unless otherwise stated, all legislative references are to the federal *Income Tax Act*.

Is the corporation electing under subsection 1101(5q) of the *Income Tax Regulations*? **101** Yes [ ] No [X]

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the tax year with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? . . . . **105** Yes [ ] No [X]

If you answered **yes**, fill out Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your corporation) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 2.

	1 Name of EPOP **110**	2 Identification number **Note 1** **115**	3 Percentage assigned under the agreement **120**
1.			
		Total	

Immediate expensing limit allocated to the corporation (see **Note 2**) . . . . **125** ________

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your corporation in column 3. If the total of column 3 is more than 100%, enter "0".

Part 2 – CCA calculation

	1 Class number Note 3 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) Note 4 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) Note 5 232	5 Adjustments and transfers Note 6 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition Note 7 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition Note 8 222	8 Proceeds of dispositions Note 9 207
1.	1		43,603,083						0
2.	1b		2,486,121	384,114					0
3.	8		1,056,790	976,933					0
4.	10		201,568	359,791					41,535
5.	12			1,029,211					0
6.	14.1		3,562,277						0
7.	45		8						0
8.	47	distribution equipment post Feb 22/05	59,243,834	11,924,988		-78,643			7,671
9.	50	Computers	6,186	254,465					0
10.	95	WIP	1,606,076			-831,417			0
11.	43.2	EV Charging Stations		25,761					0
		Totals	111,765,943	14,955,263		-910,060			49,206

	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) 234	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) Note 10	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) Note 11 236	12 Immediate expensing Note 12 238	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 Note 13 225	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0")
1.	1			43,603,083					43,603,083	
2.	1b			2,870,235			384,114	384,114	2,870,235	
3.	8			2,033,723			976,933	976,933	2,033,723	
4.	10			519,824			359,791	359,791	519,824	41,535
5.	12			1,029,211			1,029,211	1,029,211	1,029,211	
6.	14.1			3,562,277					3,562,277	
7.	45			8					8	

	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) 234	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) Note 10	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) Note 11 236	12 Immediate expensing Note 12 238	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 Note 13 225	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0")
8.	47	distribution equipment post Feb 22/05		71,082,508			11,924,988	11,924,988	71,082,508	7,671
9.	50	Computers		260,651			254,465	254,465	260,651	
10.	95	WIP		774,659					774,659	
11.	43.2	EV Charging Stations		25,761			25,761	25,761	25,761	
		Totals		125,761,940			14,955,263	14,955,263	125,761,940	49,206

Part 2 – CCA calculation (continued)

	1 Class number	Description	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the year (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the year (column 17 **multiplied** by the relevant factor) Note 14	19 UCC adjustment for property acquired during the year other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") Note 15 224	20 CCA rate % Note 16 212	21 Recapture of CCA Note 17 213	22 Terminal loss Note 18 215	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) Note 19 217	24 UCC at the end of the year (column 10 **minus** column 23) 220
1.	1					4	0	0	1,744,123	41,858,960
2.	1b		384,114			6	0	0	172,214	2,698,021
3.	8		976,933			20	0	0	406,745	1,626,978
4.	10		318,256			30	0	0	155,947	363,877
5.	12		1,029,211			100	0	0	1,029,211	
6.	14.1					5	0	0	206,674	3,355,603
7.	45					45	0	0	4	4
8.	47	distribution equipment post Feb 22/05	11,917,317			8	0	0	5,686,601	65,395,907
9.	50	Computers	254,465			55	0	0	143,358	117,293
10.	95	WIP				0	0	0		774,659
11.	43.2	EV Charging Stations	25,761	12,881		50	0	0	19,321	6,440
		Totals	14,906,057	12,881					9,564,198	116,197,742

Enter the total of column 21 on line 107 of Form T2 SCH 1, *Net Income (Loss) for Income Tax Purposes*.
Enter the total of column 22 on line 404 of Form T2 SCH 1.
Enter the total of column 23 on line 403 of Form T2 SCH 1.

Note 3: If a class number has not been provided in Schedule II of the *Income Tax Regulations* for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, *General Discussion of Capital Cost Allowance*, for exceptions to the 50% rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6). See Guide T4012 for more information about the cost of acquisitions during the year.

Note 5: A DIEP reported in column 4 is a property acquired after April 18, 2021, by a corporation that was a Canadian-controlled private corporation (CCPC) throughout the year, which became available for use in the tax year (before 2024) and was designated as such on or before the day that is 12 months after the filing-due date for the tax year to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the year in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

Note 6: Enter in column 5, "Adjustments and transfers," amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See Guide T4012 for other examples of adjustments and transfers to include in column 5.
Also include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Part 2 – CCA calculation (continued)

Note 8: Include all amounts you have repaid during the year for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the undepreciated capital cost, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter "0". The only amounts incurred before April 19, 2021, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) of the Regulations are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the tax year (total of column 12) should not exceed the lesser of:

- Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:
  - $1.5 million, if you are not associated with any other EPOP in the tax year
  - amount from line 125, if you are associated in the tax year with one or more EPOPs
  - nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the tax year with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
  - the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent tax years ending in a calendar year, if you have two or more tax years ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
  - any amount allocated by the minister under subsection 1104(3.4) of the Regulations

The immediate expensing limit has to be prorated if your tax year is less than 365 days. You cannot carry forward any unused amount of the immediate expensing limit.

- UCC of the DIEP: total of column 11

You have to maintain the CCPC status throughout the relevant tax year in order to claim the immediate expensing.

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.
Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.
Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.
See Guide T4012 for more information.

Note 14: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use respectively before 2024 or in 2024 are:

- 2 1/3 or 1 1/2 for property in Classes 43.1, 54, and 56
- 1 1/2 or 7/8 for property in Class 55
- 1 or 1/2 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 19 for additional information) and
- 0.5 or 0 for all other property that is an AIIP

If the tax year begins in 2023 and ends in 2024, the relevant factor is determined under paragraph 1100(2.01)(a) of the Regulations.

Part 2 – CCA calculation (continued)

Note 15: The UCC adjustment for property acquired during the year (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56). For special rules and exceptions, see Income Tax Folio S3-F4-C1, *General Discussion of Capital Cost Allowance*.

Note 16: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter "N/A". Then enter the amount you are claiming in column 23.

Note 17: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 18: If no property is left in the class at the end of the tax year and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 19: If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4012 for more information.
For property in Class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year.
For AIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: if the capital cost of the property was incurred before 2024, the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction), and in any other case, the amount for the year calculated in accordance with Schedule III of the Regulations
- Class 14: the lesser of 150% (if the property becomes available for use in the year and before 2024) or 125% (if the property becomes available for use in the year and after 2023) of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% (if the property is acquired in the year and before 2024) or 125% (if the property is acquired in the year and after 2023) of an amount calculated on the basis of a rate per cord, board foot, or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% (for property acquired in the year and before 2024) or 33 1/3% (in any other case) of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP provisions also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to an industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the *Income Tax Regulations* for more details.