Staff IR-1

Ref: Validation of Data used in Class B GA and CBR Allocations Tab 6.1a GA Allocation and Tab6.2a CBR_B Allocation

OEB staff has done a calculation for the kWh's entered in Tab 6.1a GA Allocation and Tab 6.2a CBR B_Allocation. Please review the calculation below and confirm Burlington Hydro agrees with OEB staff's calculation and OEB staff will update, if not please explain why.

Validation of Data used in Class B GA and CBR Allocations				
Total metered volume Excl WMP	A		1,557,033,292	Source I26 of tab 4. Billing Det. for Def-Var
Non-RPP excl WMP	B		794,387,439	Source C26 of tab 6.1 GA
Class A Full year	C		43,882,577	Source E26 of tab 6.1 GA
Class A Full Part year:				
While Class A	D	82,633,352		=+F-E
While Class B	E	83,023,011		Source D21 of tab 6.1a GA Allocation
	F		165,656,362	Source G26 of tab 6.1 GA
Total non-RPP excl WMP and full year volumes for class A customers who were class A for the full year, and the class A volumes who were class A part year	G= +B-C-D		667,871,510	Input in D20 of tab 6.1a GA Allocation
Total Class B Customers excl WMP and Full year volumes for customers who were class A for full year, and the class A customers who were class A part year	H=+A-C-D		1,430,517,363	Input in D20 of tab 6.2a CBR_B Allocation

Response:

BHI agrees with OEB staff's calculation above and has provided an updated 2019 IRM Model that includes the above changes to "Tab 6.1a GA Allocation" and "Tab 6.2a CBR_B Allocation" and the changes in BHI's responses to Staff IR-19 and Staff IR-21, "Tab 3 Continuity Schedule". An updated IRM Model is filed as Attachment Staff1_2019 IRM Model_BHI_20190124.

Staff IR-2
Ref: Tab 3 Continuity Schedule of the Rate Generator Model Column BF

BF
Principal Adjustments[1] during 2017
266,524
24,616
(266,524)

a) Burlington Hydro has made an adjustments to 1580 Variance WMS – Sub-account CBR Class B and to 1595 Disposition and Recovery/Refund of Regulatory Balances (2017), please explain the reason for the adjustments.

b) Please confirm the adjustments were not made to previously approved balances.

Response:

a) BHI made a debit adjustment to Account 1580 of $266,524 and a credit adjustment to Account 1595 (2017) for CBR rate rider recoveries from customers for the period May 1, 2017 to December 31, 2017. The approved disposition balance of the CBR sub-account was transferred to Account 1595 in accordance with OEB direction on page 11 of Burlington Hydro's 2017 IRM Application EB-2016-0059. The rate rider recoveries from May 1, 2017 to December 31, 2017 were recorded to Account 1580 in error, due to a mapping error in Burlington Hydro's billing system. An adjusting entry was made to correctly record the 2017 recoveries in Account 1595 instead of Account 1580. The mapping has since been corrected in the billing system.

   Although this was an adjustment for Burlington Hydro, in hindsight it should have been recorded in the "Transactions debit / (credit) during 2017" column of the DVA continuity schedule instead of the "Principal Adjustment during 2017" column. Burlington Hydro has filed an updated IRM model as Attachment Staff1_2019 IRM Model_BHI_20190124 which reflects this correction.

b) BHI confirms the adjustments were not made to previously approved balances.

Staff IR-3

Ref: Tab 2 (LRAMVA threshold) of LRAMVA workform

EB-2013-0115, Excel Workbook, Burlington Hydro PSA AttN 2014 CDM Adj Load Forecast 20140506, Tab LRAMVA

In the 2017 IRM application (EB-2016-0059), it was noted from tab 2 that the 2014 LRAMVA threshold was based on 2013 actuals *50% (embedded in forecast) + 2 * manual adjustment for 2014. This has resulted in a LRAMVA threshold of 7,708,624 kWh used for comparison against actuals in the current LRAMVA application.

a. Please provide the reference source of the LRAMVA threshold in row 21 of Tab 2.

b. Please explain each component of the methodology, as referenced above, to calculate the LRAMVA threshold.

   2013 actuals *50% (embedded in forecast) + 2 * manual adjustment for 2014

c. Please reconcile the LRAMVA threshold of 7,708,624 kWh against the LRAMVA threshold of 34,216,509 kWh established in EB-2013-0115 and explain why 7,708,624 kWh is used in the LRAMVA calculation.

d. Please discuss the appropriateness of including 2013 persisting savings in 2016, as shown in Tab 5, row 384, of the LRAMVA workform.

e. Please revise Table 2-a and Table 2-b to show 2014 as the year in which the LRAMVA was last established and approved by the OEB, as opposed to 2015 and 2016. Please revise Table 2-c to show 2014 as the threshold applied against actuals (i.e., removing entries in cells C47 and C48).

Response:

a) The reference source for the LRAMVA threshold is page 9 of the *2013-2015 LRAMVA Report* prepared by IndEco Strategic Consulting Inc. for the purposes of disposing of the 2013-2015 LRAMVA balances. This report was filed as evidence in Burlington Hydro's 2017 IRM Application EB-2016-0059 and is attached as Appendix A for ease of reference. The references for each component of the LRAMVA threshold are provided in Table 1 below.

b) The LRAMVA threshold is comprised of the following components as identified in Table 1 below:

- 2013 actual IESO reported results * 50% (embedded in forecast): Burlington Hydro's load forecast in its 2014 Cost of Service Application EB-2013-0015 captured 50% of the reported savings from 2013 CDM programs. The reason for this is that the load forecast captures calendar year data (1st year calendar savings = 50% of full year program savings). Only 50% of the 2013 program savings that persist into 2014 are captured in the load forecast. Therefore 50% of 2013 actuals should be included in the LRAMVA threshold.

- 2 * manual adjustment for 2014: The LRAMVA threshold also includes the 2014 estimated savings from 2014 programs of 9,417,793 kWh per Appendix 2I of Burlington Hydro per Appendix 2I of Burlington Hydro_AttE-Chapter2_Appendices_20140506 filed on May 1, 2014 as evidence in its 2014 Cost of Service Application EB-2013-0115. The reason the manual adjustment (50% of the 9,417,793kWh) is relevant is that it provided a breakdown of kWh by rate class, as identified in Column C of Table 1 below. This breakdown was multiplied by two in order to derive the LRAMVA threshold for 2014 programs by rate class. The LRAMVA threshold by rate class is therefore 2 * the manual adjustments that were made for 2014 results.

- 2011 and 2012 actual IESO reported results are excluded from the threshold because their persistence into 2014 is fully captured in the load forecast.

Table 1 – Calculation of kWh LRAMVA threshold

Rate Class	2013 results reported by IESO	2013 Results Captured in Load Forecast (50%)	2014 Manual Adjustment	Adjustment to Facilitate Comparison with 2014 results	LRAMVA Threshold
	A	B = A/2	C	D=C	E = B+C+D
Residential	1,642,521	821,261	1,591,117	1,591,117	4,003,495
GS < 50kW	5,376,385	2,688,193	499,414	499,414	3,687,021
USL	-	-	9,055	9,055	18,110
Total kWh Rate Classes	**7,018,906**	**3,509,453**	**2,099,586**	**2,099,586**	**7,708,625**
GS>50 and Streetlights (kW)	2,446,066	1,223,032	2,609,311	2,609,311	6,441,654
Total All Rate Classes	**9,464,972**	**4,732,485**	**4,708,897**	**4,708,897**	**14,150,279**
Reference	actual results from IESO - Tab 4 cell D384 LRAMVA workform	50% of 2013 results persisting into 2014	1st year savings 2014 programs = 50% of full year CDM savings = 9,417,793 kWh per Appendix 2I of Burlington Hydro_AttE-Chapter2_Appendices _20140506 filed on May 1, 2014 as evidence in EB-2013-0115	Remaining 50% of CDM savings from 2014 programs	

c) The amount of 34,216,509kWh identified in Burlington Hydro's 2014 Cost of Service application EB-2013-0115 is not the applicable threshold to be used for the purposes of determining the difference between forecasted and actual CDM savings. It represents the estimated CDM savings for 2011-2014. The 2014 LRAMVA threshold is comprised of CDM savings related to 50% of 2013 and 100% of 2014 as identified in Burlington Hydro's response to Staff-IR3b). This amount is equal to 14,150,279 kWh for all rate classes. The portion relating to customers who are billed on a kWh basis is 7,708,625 kWh. A reconciliation is provided in Table 2 below.

Table 2 – Reconciliation of CDM Savings to LRAMVA Threshold

kWh	Total CDM Savings	Excluded from LRAMVA Threshold	Included in LRAMVA Threshold	Customers Billed on a kWh basis	Customers Billed on a kW basis	Total kWh
2011	**7,238,674**	7,238,674	-	-	-	**-**
2012	**8,142,248**	8,142,248	-	-	-	**-**
2013	**9,417,793**	4,685,308	4,732,485	3,509,453	1,223,031	**4,732,484**
2014	**9,417,793**	-	9,417,793	4,199,172	5,218,622	**9,417,794**
Total	**34,216,508**	**20,066,230**	**14,150,278**	**7,708,625**	**6,441,653**	**14,150,278**

d) It is appropriate to include 2013 persisting savings in 2016 because Burlington Hydro's load forecast in its 2014 Cost of Service Application EB-2013-0015 only captured 50% of 2013 CDM savings expected to persist in 2014, as identified in its responses to Staff-IR 3b) and 3c).

e) Burlington Hydro has revised Table 2-a and Table 2-b to show 2014 as the year in which the LRAMVA was last established and approved by the OEB, as opposed to 2015 and 2016. Burlington Hydro has revised Table 2-c to show 2014 as the threshold applied against actuals (i.e., removing entries in cells C47 and C48). An updated LRAMVA Workform is provided as Attachment Staff2_LRAMVA Workform_BHI_20190124. Burlington Hydro notes that these changes do not result in any change to the LRAMVA claim.

Staff IR-4
Ref: Tab 5 (2015-2020) of LRAMVA workform

Actual savings are allocated across customer classes and are compared against forecast savings by customer class to determine lost revenue amounts.

> Please confirm the accuracy of the 0.44% allocation of savings (cell Y304) from the 2016 retrofit program to residential customers.

Response:

Burlington Hydro confirms that the 0.44% allocation of savings (cell Y304) from the 2016 retrofit program to residential customers is correct. The % allocation relates to a farm which is classified as a residential customer in Burlington Hydro's billing system but is eligible for the retrofit program as a small business.

Staff IR-5 LRAMVA workform

a. If Burlington Hydro is making any changes to the LRAMVA work form as a result of its responses to these questions, please file an updated LRAMVA work form.
b. Please confirm any changes to the LRAMVA workform in response to these LRAMVA questions by completing "Table A-2. Updates to LRAMVA Disposition (Tab 2)".

Response:

a) Burlington Hydro has made a change to the LRAMVA work form as a result of its response to Staff IR-3e only. There is no change to the proposed LRAMVA claim. An updated LRAMVA Workform is provided as Attachment Staff2_LRAMVA Workform_BHI_20190124.

b) Burlington Hydro confirms the changes identified in its response to Staff IR-3e in "Table A-2. Updates to LRAMVA Disposition (Tab 2)" of the LRAMVA Workform provided as Attachment Staff2_LRAMVA Workform_BHI_20190124.

Staff IR-6
Ref: Appendix H, page 1.

In the project summary of Project #1 under Appendix H, Burlington Hydro noted that a true-up is required due to a shortfall in load at Tremaine TS.

a. Burlington Hydro noted that Tremaine TS was required to off-load Palermo TS which was exceeding capacity. Please indicate how much load was transferred from Palermo TS to Tremaine TS and whether or not additional load could have been off-loaded to Tremaine TS.
b. In the load that has materialized in Burlington Hydro's service territory in the five years following the in-service of Tremaine TS, please indicate the amount of new load that has been connected to each of the five transformer stations serving Burlington Hydro.
c. Please indicate how much new load has been connected compared to the original forecasted loads.
d. Please provide, in table format: the station capacity, current station loading and forecasted station loading for the next five years for Burlington TS.
e. Please provide a distribution operating map for Burlington TS.

Response:

a) The load transferred from Palermo TS to Tremaine TS was 7MW in 2013. No, additional load could not be off-loaded to Tremaine TS because the pole line infrastructure was not available.

   Burlington Hydro notes that the transfer of load between Palermo TS and Tremaine TS has no impact on the calculation of the fifth year true-up. As explained in Burlington Hydro's response to VECC-5a), the Tremaine CCRA fifth year true-up will be calculated based on the combined demand at Tremaine TS and Palermo TS, not the Tremaine TS in isolation.

b) Burlington Hydro records actual load at each station – it cannot differentiate between new load and existing load by station. The change in total load connected to each of Burlington Hydro's five transformer stations in the five years following the in-service of Tremaine TS is identified in Table 3.

Table 3 – Change in Total Load by Transformer Station vs. 2012

Increase/ (Decrease) Load MW	Tremaine	Palermo	Burlington	Bronte	Cumberland	Total (MW)
2013	24.1	(7.3)	2.4	6.3	2.2	**27.7**
2014	50.0	(16.1)	(31.5)	3.4	(22.6)	**(16.7)**
2015	49.6	(29.4)	(22.5)	(5.2)	(18.0)	**(25.4)**
2016	63.8	(20.4)	(4.3)	(3.4)	(8.5)	**27.2**
2017	57.8	(22.9)	(32.5)	3.1	(27.5)	**(22.0)**

c) Table 4 below identifies the actual load compared to the original Tremaine TS forecast. The forecasted load in the Tremaine TS CCRA did not materialize for the reasons identified in Burlington Hydro's response to VECC-5c) and as a result, a fifth year true-up payment is required for the Tremaine TS CCRA.

Table 4 – Increase/(Decrease) in Load – Actuals vs. Original Forecast

Increase/ (Decrease) Load MW	Tremaine	Palermo	Burlington	Bronte	Cumberland	Total (MW)
2013	(17.7)	1.6	12.8	17.4	(10.9)	**3.3**
2014	3.6	(7.2)	(21.1)	14.5	(35.6)	**(45.8)**
2015	(1.5)	(20.5)	(12.1)	6.0	(31.0)	**(59.2)**
2016	8.1	(11.5)	6.0	7.8	(21.5)	**(11.1)**
2017	(2.6)	(14.0)	(22.1)	14.3	(40.5)	**(65.1)**

d) Burlington Hydro provides the station capacity, current station loading and forecasted station loading for the next five years for each transformer station, including the Burlington TS in Table 5 below.

Table 5 – Station Capacity and Current and Forecasted Station Loading

MW	Tremaine	Palermo	Burlington	Bronte	Cumberland	Total
Contracted Station Capacity	114.8	30.7	156.0	30.0	148.2	**479.7**
Current Load - 2018	61.8	20.2	140.8	30.0	119.6	**372.4**
Projected load - 2019	65.6	25.0	135.4	30.0	120.2	**376.2**
Projected load - 2020	68.1	25.3	135.8	30.0	120.8	**379.9**
Projected load - 2021	70.6	25.5	136.2	30.0	121.4	**383.7**
Projected load - 2022	73.2	25.8	136.6	30.0	122.0	**387.6**
Projected load - 2023	75.8	26.0	137.0	30.0	122.6	**391.4**

e) Distribution operating maps for all five transformer stations, including Burlington TS are provided as Attachment Staff3_Detailed Operating Map_BHI_20190124 (detailed map) and Attachment Staff4_Summary Operating Map_BHI_20190124 (summary map).

Staff IR-7
Ref: Appendix J, page 1 and Appendix L, page 1.

In the project summary for Project #2 under Appendix J, it was noted that one justification for additional breakers at Tremaine TS is the off-loading of Bronte TS.

a. Please provide, in table format: the station capacity, current station loading and forecasted station loading for the next five years for Bronte TS.
b. Is the need to off-load Bronte TS triggered by Burlington Hydro or another LDC?
c. Was Burlington Hydro compensated in the form of a credit for the Tremaine TS breakers as a result of off-loading Bronte TS?
d. With the additional load being transferred to Tremaine TS, does Burlington Hydro anticipate a credit for the Tremaine TS CCRA in year 10? If so, what is the expected quantum?

Burlington Hydro also stated that the additional breakers were required for load growth in the Burlington area, which is served by Tremaine TS and Palermo TS.

e. Please provide, in table format: the station capacity, current station loading and feeder loading, and forecasted station and feeder loading for the next five years at Tremaine TS and Palermo TS.
f. Please provide a distribution operating map for these two stations and where the expected load growth is anticipated.
g. Please provide the forecasted load growth for the North-East area of Burlington in the next 5 years and provide evidence to support the growth.

Burlington Hydro also stated that another driver for this project was to off-load Cumberland TS for future growth in the downtown core.

h. Please provide, in table format: the station capacity, current station loading and forecasted station loading for the next five years for Cumberland TS.
i. Please provide a distribution operating map for Cumberland TS and where the expected load growth is anticipated.
j. Please provide the forecasted load growth for the next five years for the downtown core and provide evidence to support the growth.
k. Please indicate how much load is expected to be off-loaded from Cumberland TS and when this is expected to occur.
l. Please indicate the anticipated impact of transferring load from Cumberland TS to Tremaine TS on the next CCRA true-up for Tremaine TS.

Response:

a) Please refer to Burlington Hydro's response to Staff IR-6d.

b) The need to off-load Bronte TS is triggered by Burlington Hydro.

c) No. Burlington Hydro was not compensated in the form of a credit for the Tremaine breakers as a result of off-loading Bronte TS.

d) No. Burlington Hydro does not expect a credit for the Tremaine TS CCRA in Year 10. The 5-year CCRA true-up for the Tremaine TS takes into account 25 years of load data and as such incorporates any forecasted additional load transferred to Tremaine TS.

e) Please refer to Burlington Hydro's response to Staff IR-6d.

f) Please refer to Burlington Hydro's response to Staff IR-6e for the distribution operating map. Please refer to Appendix B, Schedule B-1 for a map of where the load growth is expected to occur.

g) The forecasted load growth for the North East area of Burlington is approximately 1-2MW/year over the next five years.

   Short term growth is driven by two large green field areas in North East Burlington which have received approvals from the Ontario Municipal Board for development – the Palletta Lands and the Evergreen Lands. Burlington Hydro will service both areas from the Tremaine TS.

   Burlington Hydro relied on growth forecasts from the City of Burlington's Official Plan – February 2018 available below and has attached the following excerpts from that plan as Appendix B for ease of reference as follows:

   - Burlington Official Plan – Population and Employment
   - Burlington Official Plan – Schedule B Urban Structure
   - Burlington Official Plan – Schedule B-1 Growth Framework

   https://www.burlington.ca/uploads/21480/Doc_636536031538947602.pdf

   Schedule B identifies the two urban centres of Burlington as mixed use intensification areas (Uptown - Upper Middle Road/Appleby Line and Downtown – Brant St. and Lakeshore). Schedule B-1 identifies primary growth areas in Burlington's uptown and downtown in addition to three other areas (South East Burlington, Fairview St. and Brant St. and Aldershot). Uptown (Upper Middle Road/Appleby Line) is serviced by the

Tremaine TS. Downtown (Brant St. and Lakeshore) is serviced primarily by the Cumberland TS and Burlington TS. Existing load at Cumberland TS will be off-loaded to Tremaine TS to accommodate growth.

h) Please refer to Burlington Hydro's response to Staff IR-6d.

i) Please refer to Burlington Hydro's response to Staff IR-6e for the distribution operating map. Please refer to Appendix B, Schedule B-1 for a map of where the load growth is expected to occur.

j) The forecasted load growth for the downtown core is 0.5% per year. Please refer to the response to Staff IR-7g above for the evidence to support this growth.

k) Please refer to Burlington Hydro's response to VECC-10b).

l) There is no impact of transferring load from Cumberland TS to Tremaine TS on the 10-year CCRA true-up for Tremaine TS. As indicated in Burlington Hydro's response to Staff IR-7d, the 5-year CCRA true-up for the Tremaine TS takes into account 25 years of load data and as such incorporates any forecasted additional load transferred to Tremaine TS.

Staff IR-8
Ref: Appendix J

In the project summary for Project #2, Burlington Hydro has noted that the remaining capacity at Tremaine TS could be allocated to other load customers if the two new breakers were not purchased as per Section 6.2.10 of the Transmission System Code (TSC). However, Hydro One has performed an economic evaluation for Burlington Hydro on the basis of a load forecast as part of the CCRA. Burlington Hydro's allocated capacity specified in Schedule B of the CCRA is therefore a contracted capacity as per the definition provided in Section 6.2.3 of the TSC. Under Section 6.2.5 of the TSC, Burlington Hydro is guaranteed a capacity entitlement from Hydro One due to its contracted capacity determined in accordance with Section 6.2.4 of the TSC. As such, Burlington Hydro is guaranteed sufficient capacity based on load forecasts for the duration of its economic evaluation of 25 years. Furthermore, Burlington Hydro's capital contribution for the two breakers does not preclude Hydro One from allocating capacity to other load customers provided that excess capacity can be demonstrated as per Section 6.3.17 of the TSC. Taking into consideration the above, please explain the justification of using the two additional breakers at Tremaine TS to secure load capacity.

Response:

Burlington Hydro's justification for purchasing the two additional breakers at the Tremaine TS is to allow for full utilization of its contracted capacity of 114.75MW at the Tremaine TS; not to secure this load capacity. Burlington Hydro agrees that it is guaranteed contracted capacity of 114.75MW based on load forecasts, for the duration of its economic evaluation of 25 years. In order to utilize its full contracted capacity of 114.75MW at the Tremaine TS, Burlington Hydro requires eight breakers. Six breakers cannot accommodate Burlington Hydro's contracted capacity at the Tremaine TS at the optimal loading of each breaker. Operating with only six breakers would compromise the redundancy and reliability of the distribution system. Milton Hydro also requires two breakers and has commenced construction. It was cost efficient for Hydro One to build all four breakers at the same time.

With respect to Hydro One allocating capacity to other load customers (provided that excess capacity can be demonstrated); capacity cannot be allocated to other load customers because there are no breaker positions available. A load customer cannot use any capacity without a breaker. All breaker positions have been utilized at the Tremaine TS.

In summary Burlington Hydro's purchase of the Tremaine TS breakers was to allow for full utilization of its contracted capacity at the lowest cost option.

Staff IR-9
Ref: Application and Evidence, page 42, Table 27.

The OEB has adopted a project-specific materiality threshold, as identified in a decision for Toronto Hydro Electric System Limited.[1] The project-specific materiality threshold is as follows:

> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.[2]

Burlington Hydro was approved $420,290 in the 2014 cost of service application for Bronte Feeder Double CCT Egress, which appears to be a one-time project. It is also noted that Burlington Hydro's 2019 total net capital is $12,726,287. In this application, Burlington Hydro has requested $350,000 for a CCRA true-up.

a. Although the purpose of the funding are not the same, please explain why Burlington Hydro has difficulty absorbing the $350,000 into the total capital budget when there should be funds available from the Bronte Feeder Egress.
b. Burlington Hydro has indicated it intends to use excess capacity at Tremaine TS to off-load Bronte TS. Please explain if Burlington Hydro has explored the alternative of off-loading overloaded feeders at Bronte TS onto the two feeders at Bronte TS as part of Project #3 to reduce the amount of shortfall in the CCRA true-up.
c. Please provide the forecasted loading for the next five years in the Bronte TS Breaker CCRA and the current station loading, if load was not transferred to Tremaine TS.

Response:

a) There are no additional funds available from the Bronte Feeder Egress. Although the Bronte Feeder Egress was a one-time project in 2014, the available funds were replaced by other one-time projects such as the Metrolinx Corridor Electrification and higher expenditures in other projects such as Downtown Core Development.

   As identified in Table 24 on page 39 of Burlington Hydro's Application the Total Net Capital approved in rates was $7.730M. Burlington Hydro's 2019 Capital Budget is $12.726M. If Burlington Hydro's request for ICM funding of $3.85M is approved, it will be funding $8.876M in capital expenditures, $1.146M over that which was approved in rates i.e. Burlington Hydro will at a minimum be absorbing $1.146M into the capital budget for

[1] Toronto Hydro-Electric System Limited, "Partial Decision and Order," EB-2012-0064, April 2, 2013.
[2] Report of the Board – New Policy Options for the Funding of capital Investments: The Advanced Capital Module, EB-2014-0219, p.17.

2019. Further it absorbed $2.8MM and $1.0MM into the capital budget in 2018 and 2017 respectively (i.e. over and above that which was approved in rates).

Burlington Hydro has absorbed and is prepared to absorb a significant degree of project expenditure over and above the Board-defined threshold calculation within its capital budget. It has not applied for incremental capital funding for these amounts.

Additionally, the true-ups for the CCRAs for the Tremaine TS and the Bronte TS are interdependent – the service areas overlap and both factor in the load at the Palermo TS Therefore Burlington Hydro submits that the funding request should be considered in totality.

b) Reducing the amount of the shortfall in the CCRA true-up by off-loading overloaded feeders onto other feeders at the same TS is not an option. The CCRA true-up calculation is based on load at the TS level, not the breaker level.

c) Burlington Hydro provides an estimate of the future load at the Bronte TS had load not been transferred to the Tremaine TS in Table 6 below.

Table 6 – Future Load at Bronte TS – No Transfer to Tremaine TS

MW	No Transfer	Transfer
Current Load - 2018	33.8	30.0
Projected load - 2019	34.3	30.0
Projected load - 2020	34.8	30.0
Projected load - 2021	35.3	30.0
Projected load - 2022	35.8	30.0
Projected load - 2023	36.3	30.0

Burlington Hydro notes that any transfer of load between the Tremaine TS and the Bronte TS should have no impact to the cumulative dollar amount of the Tremaine TS and Bronte TS CCRA true-up amounts. Transferring load from the Bronte TS to the Tremaine TS will reduce the amount of the Tremaine TS CCRA true-up but increase the amount of the Bronte TS CCRA true-up by a similar amount, and vice-versa.

Staff IR-10

Ref: Capital Module Applicable to ACM and ICM
Exhibit 1/pp. 48-49

In its application, Burlington Hydro has applied for incremental capital funding related to capital contributions owed to Hydro One Networks Inc.

On sheet 10b of the Capital Module spreadsheet, the details of the proposed ICM projects are detailed. Depreciation is calculated as 1/60 of the Gross Book Value of each project, and CCA is calculated at a rate of 0.07 (7%). Burlington Hydro documents that:

> A full year of depreciation has been recovered which is consistent with the OEB's policy in ACM Report, and PILs have been calculated using a full year of Capital Cost Allowance ("CCA"). The detailed calculation of incremental revenue requirement is provided in the ICM Module filed as Attachment 7.[3]

Immediately prior to that, Burlington Hydro states that: "[t]he useful lives are consistent with those filed Burlington Hydro's 2014 Cost of Service application (EB-2013-0115)."

a) The assets for which the contributions in aid of construction are being paid by Burlington Hydro to Hydro One Networks are for assets of Hydro One's transmission network, while Burlington Hydro is a distributor. How are the 60 year useful lives and 7% CCA rate "consistent with those filed in Burlington Hydro's 2014 … application" for distribution assets?
b) Burlington Hydro's 2019 application is for the fifth year of Price Cap IR adjustments following rebasing of its rates in 2014. After requesting deferment of its rebasing for 2019 through a letter sent to the OEB on February 1, 2018, deferment was granted on August 14, 2018. Per the OEB's letter, Burlington is scheduled to apply to rebase rates through a cost of service or similar approach for 2020.

   The OEB's policy per the September 18, 2014 ACM Report and the January 22, 2016 ACM/ICM Supplemental Report is that a full-year depreciation, CCA and return on capital is allowed for all years of the price cap plan except for the final year prior to rebasing, in which case the standard half-year rule is used for calculation of the return of (depreciation) and return on capital and associated taxers/PILs for the first year that an asset enters service.[4] Since 2019 is the last year before Burlington Hydro's scheduled rebasing, please explain why it has not used the "half-year" rule for the 2019 ICM-qualifying projects.
c) Please refile the Capital Module spreadsheet based on applying the "half-year" rule for the 2019 ICM-qualifying projects.

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[3] Exhibit 1/pp. 48-49

[4] EB-2014-0218, Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, pp. 3, 23
Supplemental Report: New Policy Options for the Funding of Capital Investments, January 22, 2016, pp. 9-11

Response:

a) Burlington Hydro's rate base included contributions in aid of construction for the Tremaine TS and the Bronte TS breakers. These assets were depreciated using a useful life of 60 years and identified in the fixed asset continuity schedules. The CCA rate on these assets for the purposes of calculating PILs on the 2014 test year was 7%. The rates used in the ICM model in Burlington Hydro's 2019 IRM Application are consistent with the rates in Burlington Hydro's Cost of Service application. This is what Burlington Hydro was referring to in its statement on line 20/21 of page 48 of Exhibit 1.

b) Burlington Hydro included a full year of depreciation in the ICM model in error.

c) Burlington Hydro has updated the ICM model based on applying the "half-year" rule for depreciation for the 2019 ICM-qualifying projects. The revised model is provided as Attachment Staff5_ICM Module_BHI_20190124.

Staff IR-11
Ref: Appendix N Page 4

a) Confirm the costs included in the Z-Factor amount are incremental costs (outside of the base upon which rates were derived).
b) Confirm that the amounts are directly related to the Z-Factor event and if the wind storm event had not occurred, Burlington Hydro would not have incurred any of the costs.

Response:

a) Burlington Hydro provides a revised calculation for the Z-factor claim in Tables 7-10 below. The Z-factor claim of $368,487 previously submitted included overhead burdens of $51,532 in operating expenses in error. These costs are not incremental. Tables 7 and 8 below incorporate the removal of these overhead burdens. Burlington Hydro confirms that the costs included in the revised Z-Factor amount of $316,956 are incremental costs (outside of the base upon which rates were derived).

Burlington Hydro has also revised its Z-factor claim to include carrying charges. Burlington Hydro will be recording extraordinary event costs in Account 1572 which attracts carrying charges as identified in the Board's *Accounting Procedures Handbook for Electricity Distributors* effective January 1, 2012.

Table 7 –Z-Factor Event Costs (Revised Table 1 of Appendix N)

Category	Operating $	Capital $	Total $
Incremental Labour/Material/Vehicle Costs	$143,955	$55,090	$199,045
3rd Party Contractors	$89,215	$233,602	$322,817
Grid Smart City Partners	$61,944	$43,986	$105,930
Total	**$295,115**	**$332,678**	**$627,793**

Table 8 – Z-Factor Relief Requested (Revised Table 2 of Appendix N)

Category	Amount $
Operating Costs	$295,115
Capital Expenditures	$21,841
Total before Carrying Charges	**$316,956**
Carrying Charges	$6,289
Total Z-Factor Claim	**$323,245**

Table 9 – Z-Factor Carrying Charges

Month	Opening Balance	Interest Rate	Monthly Carrying Charges	Total Principal and Carrying Charges
May-18			$0	$316,956
Jun-18	$316,956	0.155%	$492	$317,448
Jul-18	$316,956	0.161%	$509	$317,957
Aug-18	$316,956	0.161%	$509	$318,466
Sep-18	$316,956	0.155%	$492	$318,958
Oct-18	$316,956	0.184%	$584	$319,542
Nov-18	$316,956	0.178%	$565	$320,108
Dec-18	$316,956	0.184%	$584	$320,692
Jan-19	$316,956	0.208%	$660	$321,351
Feb-19	$316,956	0.188%	$596	$321,947
Mar-19	$316,956	0.208%	$660	$322,606
Apr-19	$316,956	0.201%	$638	$323,245
Total	**$316,956**		**$6,289**	**$323,245**

Table 10 – Determination of Proposed Z-Factor Rate Riders (Revised Table 4 of Appendix N)

Rate Class	2014 CoS (EB-2013-0115) Revenue Requirement	Allocation of Revenue Requirement	# of customers/ connections as at Dec 31, 2017	Monthly Rate Rider
Residential	$17,480,231	$195,952	60,593	$0.27
GS < 50kW	$3,864,127	$43,317	5,523	$0.65
GS > 50kW	$7,138,613	$80,023	1,006	$6.63
Unmetered Scattered Load	$113,055	$1,267	582	$0.18
Street Lighting	$239,506	$2,685	15,386	$0.01
Total	**$28,835,532**	**$323,245**	[redacted]	[redacted]

b) Burlington Hydro confirms that that the amounts identified in Table 7 and 8 above are directly related to the Z-Factor event and if the wind storm event had not occurred, Burlington Hydro would not have incurred any of the costs.

Staff IR-12
Ref: Appendix N

a) Indicate the cost categories and dollar amounts that have not been audited in relation to the restoration of power after the wind storm.
b) Indicate when all costs will be audited.

Response:

a) None of the cost categories and dollar amounts have been audited in relation to the restoration of power after the wind storm. Current year amounts are not audited until the following fiscal year.

   Burlington Hydro notes that as indicated in the OEB's *Report of the Board on 3rd Generation Incentive Regulation*, "*distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will permit the Board and any affected distributor to address extraordinary events in a timely manner".*[5]

b) The costs will be audited in February 2019, during Burlington Hydro's external financial audit.

[5] Report of the Board on 3rd Generation Incentive Regulation, July 14, 2008, page 37

Staff IR-13
Ref: Appendix N Page 6

a) Provide a copy of Burlington Hydro's Emergency Operations Plan.
b) Discuss any deviations from Burlington Hydro's Emergency Operations Plan.
c) Explain who Burlington Hydro's alliances were that they relied on.
d) Clarify whether Burlington Hydro paid any premium amounts to its third-party contractors.
e) Provide a separate schedule (breakdown) of each Third Party Contractor invoice based on labour, materials, accommodations, meals, truck, other (provide explanation).
f) Quantify the costs that would have been avoided from third party contractors had the support been available under the mutual aid agreement and from alliances.

Response:

a) Burlington Hydro provides a copy of its Emergency Operations Plan as Attachment Staff6_Emergency Operations Plan_BHI_20190124.

b) There were no deviations from Burlington Hydro's Emergency Operations Plan.

c) Burlington Hydro relied on its GridSmartCity partners (K-Line and two GridSmartCity utilities).

d) Burlington Hydro paid overtime labour rates to its third party contractors as the event occurred on the weekend.

e) Burlington Hydro provides a breakdown of each third party contractor invoice in Table 11 below.

Table 11 – Breakdown of Third Party Contractor Invoices

Invoice #	Labour	Materials	Lodging	Truck	Total
Invoice 1	$5,400	$0	$0	$0	**$5,400**
Invoice 2	$225	$0	$0	$0	**$225**
Invoice 3	$1,100	$0	$0	$0	**$1,100**
Invoice 4	$9,450	$0	$0	$0	**$9,450**
Invoice 5	$825	$0	$0	$0	**$825**
Invoice 6	$9,450	$0	$0	$0	**$9,450**
Invoice 7	$2,025	$0	$0	$0	**$2,025**
Invoice 8	$3,150	$0	$0	$0	**$3,150**
Invoice 9	$2,025	$0	$0	$0	**$2,025**
Invoice 10	$6,300	$0	$0	$0	**$6,300**
Invoice 11	$1,579	$0	$0	$0	**$1,579**
Invoice 12	$7,880	$9,010	$0	$1,600	**$18,490**
Invoice 13	$980	$485	$0	$0	**$1,465**
Invoice 14	$2,526	$1,450	$0	$1,546	**$5,523**
Invoice 15	$181,608	$0	$0	$0	**$181,608**
Invoice 16	$8,757	$0	$0	$0	**$8,757**
Invoice 17	$0	$0	$5,389	$0	**$5,389**
Invoice 18	$1,240	$0	$0	$0	**$1,240**
Invoice 19	$10,572	$5,028	$0	$0	**$15,600**
Invoice 20	$0	$53	$0	$0	**$53**
Invoice 21	$0	$105	$0	$0	**$105**
Invoice 22	$350	$0	$0	$0	**$350**
Invoice 23	$700	$0	$0	$0	**$700**
Invoice 24	$350	$0	$0	$0	**$350**
Invoice 25	$1,723	$0	$0	$0	**$1,723**
Invoice 26	$2,966	$0	$0	$0	**$2,966**
Invoice 27	$1,806	$0	$0	$0	**$1,806**
Invoice 28	$2,039	$0	$0	$0	**$2,039**
Invoice 29	$3,746	$0	$0	$0	**$3,746**
Invoice 30	$596	$0	$0	$0	**$596**
Invoice 31	$464	$0	$0	$0	**$464**
Invoice 32	$1,244	$0	$0	$0	**$1,244**
Invoice 33	$398	$0	$0	$0	**$398**
Invoice 34	$5,961	$0	$0	$0	**$5,961**
Invoice 35	$385	$0	$0	$0	**$385**
Invoice 36	$2,205	$0	$0	$0	**$2,205**
Invoice 37	$1,790	$0	$0	$0	**$1,790**
Invoice 38	$2,380	$0	$0	$0	**$2,380**
Invoice 39	$1,771	$0	$0	$0	**$1,771**
Invoice 40	$2,084	$0	$0	$0	**$2,084**
Invoice 41	$2,890	$0	$0	$0	**$2,890**
Invoice 42	$750	$0	$0	$0	**$750**
Invoice 43	$375	$0	$0	$0	**$375**
Invoice 44	$813	$0	$0	$0	**$813**
Invoice 45	$1,350	$0	$0	$0	**$1,350**
Invoice 46	$1,130	$0	$0	$0	**$1,130**
Invoice 47	$1,633	$0	$0	$0	**$1,633**
Invoice 48	$1,130	$0	$0	$0	**$1,130**
Invoice 49	$30	$0	$0	$0	**$30**
Total	**$298,150**	**$16,132**	**$5,389**	**$3,146**	**$322,817**

f) The support provided by third party contractors was not available under the GridSmartCity mutual aid agreement or existing alliances. Burlington Hydro allocated all external work that it could not handle itself to GridSmartCity partners first. Any remaining work conducted by third party contractors was specialized and not covered under any mutual aid agreements or existing alliances. The remaining work included hydrovac evacuation services, environmental clean-up and tree trimming. Therefore there were no costs that could have been avoided.

Staff IR-14
Ref: Appendix N

Provide Burlington Hydro's annual Emergency Maintenance amounts (budgeted and included in rates, compared to actual expenditures), for the period 2014 and to-date.

Response:

Burlington Hydro does not budget or track emergency maintenance amounts separately. Please refer to Burlington Hydro's response to VECC-14h) and i) for further details.

Emergency Maintenance expenditures are included in Burlington Hydro's distribution maintenance expenditures. Burlington Hydro provides its annual distribution maintenance expenditures compared to that which was included in rates in Table 12 below. Burlington Hydro has incurred $20,583,850 in distribution maintenance expenditures from 2014 to 2018, an increase of $1,262,263 over the amount that is included in rates.

Table 12 - Annual Distribution Maintenance Expenditures

Year	Board Approved (EB-2013-0115)	Actuals	Actuals vs. Board Approved Higher/(Lower)
2014	$3,864,317	$2,609,626	($1,254,692)
2015	$3,864,317	$3,701,170	($163,148)
2016	$3,864,317	$4,198,648	$334,330
2017	$3,864,317	$5,098,438	$1,234,121
2018 Estimate	$3,864,317	$4,975,969	$1,111,651
Total	**$19,321,587**	**$20,583,850**	**$1,262,263**

Staff IR-15
Ref: Appendix N

a) Provide a breakdown of all Burlington Hydro's internal labour costs applicable for the affected period using the following format.

Department	Number of Eligible Employees	Regular Hours Worked	Total Regular Time Payments	Overtime Hours Worked	Total Overtime Payments
Management					
Other Non-Union Employees					
Subtotal Non-Union					
Union Employees:					
Operations					
Other					
Subtotal Union					
Total Internal Labour for Affected Period					
Total Z-factor Labour Costs					

b) Provide Burlington Hydro's policy with respect to overtime for its non-union employees and management.
c) Describe whether the z-factor labour costs included payments made to union employees at regular rates of pay for work on pre-scheduled vacation days.

Response:

a) A breakdown of Burlington Hydro's internal labour costs (capital and operating) applicable for the affected period is provided in Table 13 below.

Table 13 – Internal Labour Costs – Z-Factor

Department	Number of Eligible Employees	Regular Hours Worked	Total Regular Time Payments	Overtime Hours Worked	Total Overtime Payments
Management					
Other Non-Union Employees	3	80	$3,960	147	$7,275
Subtotal Non-Union	**3**	**80**	**$3,960**	**147**	**$7,275**
Union Employees:					
Operations	27	593	$25,365	823	$80,218
Other					
Subtotal Union	**27**	**593**	**$25,365**	**823**	**$80,218**
Total Internal Labour for Affected Period					
Total Z-factor Labour Costs	**30**	**673**	**$29,325**	**970**	**$87,493**

b) Burlington Hydro attaches its Overtime Policy for Management/Non-Union employees as Appendix C.

c) No, the Z-factor labour costs did not include payments made to union employees at regular rates of pay for work on pre-scheduled vacation days. There were no-prescheduled vacation days during the Z-factor event.

Staff IR-16
Ref: Appendix N

Burlington Hydro did not indicate it assisted neighboring communities once power was restored to its customers.

a) Please confirm Burlington Hydro did not assist other LDCs.
b) If Burlington Hydro did assist neighboring communities, did it charge a premium to assist other LDCs

Response:

a) Burlington Hydro confirms that it did not assist other LDCs.

b) N/A

Staff IR-17
Ref: GA Analysis Workform Appendix A

In response to question 1, Burlington Hydro has indicated that for CT 148, it initially records the entire CT 148 to Account 1589 and then moves the portion of the invoice related to RPP customers to Account 1588. The portion of the invoice related to RPP customers is calculated by multiplying RPP quantities by the GA rate on the IESO invoice.

a) A GA rate is not actually provided on the IESO invoice. As such, please explain how the Applicant calculates the actual GA Rate for a particular month from the information provided on the IESO invoice.
b) Does the approach used by Burlington Hydro leave the difference between the approved and actual loss factors entirely in Account 1589? If not, then please explain how.
c) If Burlington Hydro's approach does ultimately leave the difference between the approved and actual loss factors entirely in Account 1589, then doesn't a portion of that balance also relate to RPP consumption and therefore should be allocated for disposition to Non-RPP customers? Please explain.
d) Please quantify the impact of b) above (i.e. how much of the total difference in loss factor should have been allocated to Account 1588 for the period but is currently included in Account 1589).
e) With respect to the calculation performed to transfer a portion of CT148 from Account 1589 to Account 1588::
    a. Please explain how the RPP quantities used in the above calculation are determined. Are the RPP quantities an estimate or are they based on the actual RPP quantities for the particular month? Please explain.
    b. If they are actual RPP quantities for the month, then please explain how that information is known at the time of recording the monthly CT 148 charge from the IESO.
    c. If the RPP quantities that are used in the allocation calculation above are based on an estimate, then why does the utility indicate (in Appendix A Responses) that a true-up to that allocation is not required. Wouldn't an adjustment be required based on the actual RPP quantities for the month once they become available? Please explain.

Response:

a) Burlington Hydro calculates the actual GA rate by dividing the Class B GA (CT 148) on the IESO invoice by total Class B kWh consumption.

b) Yes, the approach used by Burlington Hydro leaves the difference between the approved and actual loss factors entirely in Account 1589.

c) Burlington Hydro has answered this question assuming that the OEB was referring to allocating a portion of the balance for disposition to RPP not non-RPP customers in its Interrogatory Staff IR-17c.

   In theory a portion of the balance of the difference between the approved and actual loss factors relates to RPP consumption and therefore should be allocated for disposition to RPP customers. However this amount is immaterial as identified in Burlington Hydro's response to Staff IR-17d.

d) The impact of the total difference in loss factor that should have been allocated to RPP customers is $37K.

e)

   a. The RPP quantities used to transfer a portion of CT148 from Account 1589 to Account 1588 are the same RPP quantities used to determine the RPP vs. Market Price Claim. This calculation has been provided in Table 15, page 25, Exhibit 1 of Burlington Hydro's 2019 IRM Application EB-2018-0021.

      The RPP consumption is an estimate. Actual RPP consumption is not available from Burlington Hydro's billing system as identified on Lines 7 to 13, page 26, Exhibit 1 of Burlington Hydro's 2019 IRM Application.

   b. N/A. The RPP quantities are not actual. Please refer to the response to Staff IR e) a.

   c. Burlington Hydro agrees that an adjustment would be required based on actual RPP consumption for the month if it were available. However, Burlington Hydro does not have access to actual RPP consumption for the month in its billing system as explained on Lines 7 to 13, page 26, Exhibit 1 of Burlington Hydro's 2019 IRM Application. Burlington Hydro is aware that ideally, actual RPP consumption should be used to determine the RPP vs. Market Price Claim. Burlington Hydro expects to refine its RPP vs. Market Price claim calculation when it transitions to a new Customer Information System in 2020.

Staff IR-18
Ref: Application and Evidence, page 25, Table 15.

At the above reference, Burlington Hydro presents a table that describes how its initial monthly settlement with the IESO is calculated, and how that settlement is subsequently trued up to actual in the following month.

a) Please confirm that the initial estimate of embedded generation that is used for settlement purposes is not trued up to actual for the particular settlement month being settled but rather, the trued up is to the actual embedded generation volume of the previous month (meaning that there is a one month lag). If so, please explain why?
b) Does this not mean that a true-up for the December 2017 embedded generation (or the actual embedded generation for December 2017) is not accounted for in the 2017 balances per the DVA continuity schedule? Please explain
c) Please quantify the related dollar impact.

Response:

a) Burlington Hydro confirms that the initial estimate of embedded generation that is used for settlement purposes is not trued up to actual for the particular settlement month being settled but rather, the trued up amount is to the actual embedded generation volume of the previous month (meaning that there is a one month lag). Historically this difference has not been material. The majority of Burlington Hydro's embedded generation is solar and there is minimal generation in December.

b) Burlington Hydro confirms that a true-up for the December 2017 embedded generation (or the actual embedded generation for December 2017) is not accounted for in the 2017 balances per the DVA continuity schedule. However the difference is immaterial.

c) The related dollar impact is $953 (receivable from the IESO).

Staff IR-19
Ref: GA Analysis Workform

Cell C 62 of the GA Analysis Workform must represent the actual transactions recorded in Account 1589 during the period. Burlington Hydro has recorded an amount in this cell that does not correspond to the “Transactions Debit / (Credit) during 2017” column of the DVA Continuity schedule.

a) If the balance in the GA Analysis Workform (Cell C 62) represents the actual transactions for the year as recorded in the G/L, then this is the amount that should be presented in the column “Transactions Debit/(Credit) during 2017” per the DVA continuity schedule. Please adjust accordingly.

b) If the balance that is currently in the “Transactions Debit/(Credit) during 2017” column for Account 1589 also includes the reversal of the principal adjustments of $681,404 that was included in the 2016 balance of Account 1589 and approved for disposition by the OEB in EB-2017-0029, then the reversal of this amount must instead be presented in the “Principal Adjustments during 2017” column for Account 1589.

Response:

a) The originally filed DVA continuity schedule included the reversal of the principal adjustments of $681,404 in the column “Transactions debit / (credit) during 2017” approved for disposition by the OEB in Burlington Hydro’s 2018 IRM Application EB-2017-0029. This amount should have been presented in the column “Principal Adjustments during 2017” on the DVA continuity schedule.

b) Burlington Hydro has updated the DVA continuity schedule to include the debit entry of $681,404 in the column “Principal Adjustments during 2017” and removed it from the column “Transactions debit / (credit) during 2017”. Cell C62 of the GA Analysis Workform now balances to the “Transactions Debit / (Credit) during 2017” column of the DVA Continuity schedule. An updated IRM Model reflecting this change is filed as Attachment Staff1_2019 IRM Model_BHI_20190124.

Staff IR-20
Ref: DVA Continuity Schedule, Account 1588

Burlington Hydro is seeking disposition of approximately $3.2 million in account 1588 (recovery from ratepayers).

Given that any variance between the RPP revenue and the cost of energy and GA attributable to RPP customers should get settled directly with the IESO on a monthly basis, the expectation is that any remaining amounts in account 1588 would be relatively small and close to zero (primarily comprised of the difference between amounts billed at the approved total loss factor versus actual system losses for the year).

a) Based on the above expectation, Burlington Hydro's balance in account 1588 of debit $3.2 million appears to be unusually large. Please explain what comprises the balance in account 1588 as at December 31, 2017.
b) With respect to its monthly settlements with the IESO, the Applicant has indicated that they true-up to actual consumption in the month following settlement with the exception of its non-RPP non Interval Metered and Retailer Customers, for which it uses billed data as a proxy for actual consumption. For purposes of determining how material this class of customer is, please provide a table for 2017 that shows the actual monthly consumption by customer class compared to the total utility purchases from the IESO for each month.

Response:

a) Burlington Hydro agrees that the expectation is that any amounts in Account 1588 should be close to zero and that its debit balance in Account 1588 of $3.2M is large.

   This amount is due to the calculation of unbilled revenue. As previously discussed in Burlington Hydro's response to Staff IR-17e.(c), actual consumption kWh and associated dollars attributable to a particular month/year are not available from Burlington Hydro's billing system for certain customers. This can generate a difference between revenue and expense recorded from year to year; however these differences over time should net to zero. Burlington Hydro expects to refine these calculations when it transitions to a new Customer Information System in 2020.

b) Burlington Hydro provides the 2017 actual/estimated monthly consumption by customer class compared to the total utility purchases from the IESO for each month in Table 14 below.

Table 14 – 2017 Monthly Consumption by Customer Class

2017 kWh Consumption	IESO Purchases plus Generation		Class A	Class B - non-RPP Interval	Class B - non-RPP non-Interval	Class B - RPP
January	140,244,141		3,870,618	37,362,689	28,554,168	70,456,666
February	122,589,890		3,531,553	38,831,047	26,157,283	54,070,007
March	134,859,090		4,010,614	34,408,267	30,259,402	66,180,807
April	117,704,730		3,715,167	39,376,771	23,112,625	51,500,167
May	124,976,583		3,906,238	39,674,385	24,379,320	57,016,640
June	139,937,228		3,952,918	40,510,181	23,721,476	71,752,653
July	154,058,236		18,659,884	42,003,372	13,960,776	79,434,204
August	149,734,039		19,072,994	30,715,462	23,265,070	76,680,513
September	138,189,238		18,298,704	30,941,299	21,884,242	67,064,993
October	126,371,466		18,534,676	29,654,449	20,816,931	57,365,410
November	127,314,371		17,815,065	28,654,098	19,533,421	61,311,787
December	139,906,126		15,896,437	27,858,470	20,210,530	75,940,689

Staff IR-21
Ref: DVA Continuity Schedule, Account 1588

In its EB-2017-0029 IRM Application, the OEB approved principal adjustments to Account 1588 of debit $624,435 (as recorded in the "Principal Adjustments during 2016" column of the DVA continuity schedule approved in that proceeding). Accordingly, a reversing entry of credit $624,435 would need to be recorded in the 2017 DVA continuity schedule in the column "Principal Adjustments during 2017". Based on the DVA continuity schedule submitted as part of this application, no reversing adjustment was recorded to account 1588.

a) Please update the DVA continuity schedule to present the reversal of this balance as a principal adjustment to Account 1588 as at December 31, 2017.
b) If the applicant has already recorded the reversal of this balance in the "Transactions debit / (credit) during 2017" column of the DVA continuity schedule, then please remove from that column and present as a "Principal Adjustment during 2017".

Response:

a) Burlington Hydro has updated the DVA continuity schedule to include the credit entry of $624,435 in the column "Principal Adjustments during 2017" to reflect the reversal of the principal adjustment of $624,435 to Account 1588, as approved in Burlington Hydro's 2018 Application EB-2017-0029. An updated IRM Model is filed as Attachment Staff1_2019 IRM Model_BHI_20190124.

b) The reversal entry identified in response to Staff IR-21a) was previously included in the "Transactions debit / (credit) during 2017" column of the DVA continuity schedule and has been removed from that column and presented as a "Principal Adjustment during 2017".

Staff IR-22
Ref: GA Analysis Workform, Note 5

Burlington Hydro presented a number of reconciling adjustments in Note 5 of the GA Analysis Workform:

a) Please explain why adjustments 2a and 2b in Note 5 of the GA Analysis Workform would be zero? Burlington Hydro records an unbilled revenue accrual each month and it is expected there would be a difference between what was accrued and what was billed subsequently? Please explain.

b) Please explain the nature of the billing adjustment of $121K that was recorded as adjustment 5 in the GA Analysis Workform.

c) How is the applicant certain that this billing adjustment is related entirely to Non-RPP customers and therefore should be entirely allocated to account 1589? Please explain.

d) Please provide the calculation used to quantify adjustment 7 of the GA Analysis Workform related to the impact of the difference between actual system losses and billed TLFs.

e) Please explain the cause of the difference between the IESO posted rate and the actual invoice received from the IESO. Please provide the supporting calculations for how the reconciling adjustment amount was quantified (adj 6).

Response:

a) The unbilled revenue accrual for December is calculated using actual billed kWh for not consumption kWh. Consumption kWh by calendar month is unavailable in Burlington Hydro's billing system for certain customers as identified in Burlington Hydro's response to Staff IR-17e(c). Since the unbilled revenue accrual for December uses actual bills to determine consumption, Burlington Hydro has no better estimate of consumption available. Therefore there is no true-up required for the unbilled revenue accrual and no adjustment is made.

b) The billing adjustment of $121K is attributable to two customers. One customer was billed at RPP pricing (GA allocated to Account 1588) instead of spot pricing (GA allocated to Account 1589). The other customer was a primary metered customer and billed as a secondary metered customer in error – this generated a correction to GA revenue.

c) Burlington Hydro retains records of billing adjustments by customer. Both customers to whom the billing adjustment relates are non-RPP customers and therefore the amount should be entirely allocated to account 1589.

d) Burlington Hydro provides the calculation used to quantify adjustment 7 of the GA Analysis Workform related to the impact of the difference between actual system losses and billed total loss factors in Table 15 below. This amount is an estimate calculated only for the purposes of ensuring the losses did not contribute to a material difference on the GA Workform.

Table 15 - Difference between Actual System Losses and Billed Total Loss Factors

2017	Formula	Amount
kWh IESO per workform	A	689,935,139
Actual Loss	B = L	3.6421%
kWh Delivered	C = A*(1-B)	664,807,164
Billed Loss	D	3.7300%
kWh Billed	E = C*(1+D)	689,604,471
kWh differential	F = E-A	($330,668)
Average GA Rate/kWh	G	$0.10024
Revenue Over/(Under) Stated in Account 1589	**H = F*G**	**($33,148)**

2017 Losses as per RRRs	Formula	Amount
Supply (expense)	I	1,615,885,086
Delivery (revenue)	J	1,557,033,292
Losses	K = I-J	58,851,794
Losses %	L = K/I	3.6421%

e) The cause of the difference between the IESO posted rate and the actual invoice received from the IESO is rounding. The posted rate per MWh is calculated to 2 decimal places; the rate used in Burlington Hydro's financial statements is imputed based on the Global Adjustment $ amount invoiced by the IESO divided by kWh consumption. The supporting calculations are provided in Table 16 below. The amount is immaterial – Burlington Hydro calculated the amount to ensure its financial statements reflect the posted rate and that there is no material difference on the GA Workform.

The amount identified below is $5,493 as compared to ($20,464) on the GA Analysis Workform. There was a formula (linking) error in the GA Analysis Workform. Burlington Hydro provides a revised GA Analysis Workform as Attachment Staff7_GA Analysis Workform_BHI_20190124.

Table 16 – Calculation of Difference Between Posted Rate and Actual Rate

	Billed GA	Posted GA	$ Impact
Billed kWh	689,935,139	689,935,139	[redacted]
$	$69,460,989	$69,455,496	$5,493
Average $/MWh	$100.678	$100.670	$0.008

Appendix A
IndEco Strategic Consulting Inc.
2013-2015 LRAMVA Report

IndEco
Strategic Solutions for a Changing World™

Burlington Hydro Inc. 2013-2015 LRAMVA

Burlington Hydro Inc. lost revenue related to Conservation and Demand Management

2013-2015

This document was prepared for Burlington Hydro Inc. by IndEco Strategic Consulting Inc.

For additional information about this document, please contact:

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77 Mowat Avenue, Suite 412
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Tel: 416 532-4333
E-mail: **info@indeco.com**

IndEco report B6112

21 September 2016

Contents

Introduction

The Lost Revenue Adjustment Mechanism ("LRAM") was developed to remove a disincentive electricity local distribution companies ("LDCs") may have to promote conservation and demand management ("CDM") programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of LDCs, which directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that resulted from CDM programs the LDC offered to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts an LDC included in the LDC's load forecast.[1]

Burlington Hydro Inc. (BHI) contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers in a variety of rate classes for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period. BHI is required to use "the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation."[2] The final 2015 annual verified results report is the most recent final CDM evaluation report available from the IESO. Thus, BHI may claim lost revenue from CDM programs up to and including 2015 in BHI's 2017 IRM application (EB-2016-0059).

BHI submitted a claim for lost revenues from 2011–2012 CDM programs in its 2014 Cost of Service application (EB-2013-0115). The impacts of CDM in 2012 and prior years are captured in the load forecast for BHI's 2014 cost of service rate case. Thus, BHI's LRAMVA for 2015 and subsequent years does not include CDM program impacts from 2012 and prior years. This report determines the variance account balance for the following revenue losses:

- Lost revenues in 2013 related to programs offered in 2011,
- Lost revenues in 2013 related to programs offered in 2012,
- Lost revenues in 2013 related to programs offered in 2013,
- Lost revenues in 2014 related to programs offered in 2013,
- Lost revenues in 2014 related to programs offered in 2014.
- Lost revenues in 2015 related to programs offered in 2013,
- Lost revenues in 2015 related to programs offered in 2014, and

[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

[2] *Filing Requirements For Electricity Distribution Rate Applications - 2016 Edition for 2017 Rate Applications - Chapter 2 - Cost of Service*, Ontario Energy Board. July 14, 2016.

- Lost revenues in 2015 related to programs offered in 2015.

The carrying charges on the above variances through April 2017 are also reported.

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the different time periods of results data and the rate year, and the need to determine carrying charges on the lost revenues.

The most recent input assumptions currently available have been used to calculate the lost revenue values.

CDM results

From 2011 through 2015, BHI offered provincial programs in partnership with the Independent Electricity System Operator (IESO). BHI did not offer custom programs beyond the IESO programs.

IESO evaluation results

The IESO performs evaluations of all of its programs, which examine gross energy savings from the programs, and the net-to-gross ratio (NTGR), and then from those calculates net energy savings by initiative within program group (residential, business, industrial and low-income). Peak load reductions are also calculated, and reported in the same way.

Provincial results are allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reports energy savings and peak demand reductions, by initiative in the current year, adjustments to the previous year, based on updated validation, and contribution to total savings or reductions to the end of the 2011 to 2014 period and the 2015 to 2020 period. The savings and demand reductions for a particular year for a number of programs persist in the following years. The savings and demand reductions for demand response programs do not persist beyond the year in which those particular savings and demand reductions occur. The IESO was requested to provide the persistence into future years of savings and reductions for each program in each year.

These are the best, most definitive and defensible estimates of results associated with these programs, and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Allocating results to rate classes

The IESO reports results by 'program', within four main programs: residential, business (commercial and institutional), industrial and low-income. These only partially map onto rate classes. For initiatives that apply to more than one rate class, BHI staff estimated the split by rate class, drawing on participant-specific information where available.

Application of reported results

As previously mentioned, the IESO reports both energy savings and reductions in demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW), the IESO reported demand reductions are used to calculate lost revenues related to CDM results. The demand reductions in the IESO reports should be multiplied by a multiplier based on the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year…In the case of the Building Commissioning initiative, the demand savings provided in the Final CDM Results should only be multiplied by three (3) as these savings are related to space cooling and do not occur throughout the full year, but only during the summer months, typically."[3]

The OEB has decided that lost revenue cannot be claimed from the kW values reported by the IESO for the Demand Response 3 (DR3) program. "The monthly peak demand of a demand-billed customer used for billing purposes may not correspond with the demand response event; even if it did, the lost revenues would only be related to a difference between the customer's peak demand absent the demand response event and the next highest peak demand for the customer in that month… Since the IESO's evaluations cannot confirm the nature of the demand savings relative to the billing period for demand-billed customers, it is not appropriate that distributors be credited with lost revenues from demand response programs, except for those situations where the distributor can explicitly demonstrate revenue impacts."[4]

---

[3] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2016-0182, May 19, 2016, p. 4.

[4] Ibid. p. 7.

Load reductions accounted for in the load forecast

In recent years, LDCs have tried to account for load losses due to CDM programs in their load forecasts, submitted as part of their Cost of Service applications. These forecasted reductions need to be deducted from load losses attributable to CDM programs, to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

Distribution rates

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues. An exception is for certain rate riders related to taxes, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

For most electricity distribution utilities in Ontario, including BHI, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported for the calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average rate is estimated based on the rate being four twelfths of the current year's rate (for January through April), and eight twelfths of the previous year's rate (for May through December).

Lost revenues variance

Lost revenues in a particular rate class are the product of the savings or demand reductions in that class, less what was accounted for in the load forecast, multiplied by the average rate for that class in the calendar year for which the energy savings or demand reductions were reported.[5] The variance is the difference between these lost revenues and the quantity of CDM in the load forecast, or what is called 'the LRAMVA threshold'.

Because these revenues are lost throughout the year, and are only recovered through rate riders in subsequent years, the Ontario Energy

[5] Where distribution rates are monthly rates for the peak kW in that month, the annual loss of revenue is the monthly rate times the number of months it applies to – usually twelve.

Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB, and published on the Board's website. The carrying charges are simple interest, not compounded and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. So 1/12 of the annual results are allocated to each month of the year.

Carrying charges accrue from the time of the results, until disposition.

The LDC reports these lost revenues on its financial statements in Account 1568, and the associated rate class-specific sub-accounts.

Results

Following the methodology described above, lost revenues were calculated for BHI.

CDM results

IESO evaluation results

The most recent and appropriate final CDM evaluation reports from the IESO were used in support of the lost revenue calculations. A working Microsoft Excel file copy of each IESO evaluation report has been filed separately by BHI. The net verified final 2011-2014 results can be found in Table 1 of the *Verified 2011-2014 Final Results Report for Burlington Hydro Inc.* file released by the IESO on September 1, 2015. The net adjustments to verified final 2011, 2012, and 2013 results can be found in Table 2 of the *Verified 2011-2014 Final Results Report for Burlington Hydro Inc.* file released by the IESO on September 1, 2015. The net verified final 2015 results can be found in the "Net Incremental First Year Energy Savings" and "Net Incremental First Year Peak Demand Savings" sections of the "LDC Progress" tab in the *Final 2015 Annual Verified Results Report for Burlington Hydro Inc.* file released by the IESO on June 30, 2016.

The IESO provided BHI with persistence data for 2013 and 2015 results and 2012 adjustments. Persistence for results in 2011, 2012 and 2014 were estimated from these values by applying the same rate of loss of persistence to each initiative as was seen for 2013.

Table 16 of the OEB LRAMVA work form shows the estimated persistence of 2011 results into future years. Table 17 of the OEB LRAMVA work form shows the persistence of 2012 results into future years. Table 18 of the OEB LRAMVA work form shows the persistence of 2013 results into future years. Table 19 of the OEB LRAMVA work form shows the estimated persistence of 2014 results through 2015. Table 20 of the OEB LRAMVA work form shows the estimated persistence of 2011 adjustments into future years. Table 21 of the OEB LRAMVA work form shows the persistence of 2012 adjustments into future years. Table 22 of the OEB LRAMVA work form shows the estimated persistence of 2013 adjustments into future years. No adjustments were provided for 2014 final results.

Allocating results to rate classes

BHI provided information on the allocation of results to rate classes. In most cases, the allocation is straightforward. Initiatives that can span multiple rate classes include Retrofit, Building Commissioning, New

Construction, Energy Audit, Demand Response 3, Process & Systems Upgrades, Monitoring & Targeting, Energy Manager, Electricity Retrofit Incentive Program and High Performance New Construction. No allocation was provided for programs for which BHI has no program results.

BHI bills customers in different rate classes using different volumetric units, either kilowatt hours (kWh), or customer peak monthly kilowatts (kW). The rate classes (and billing units) for BHI are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS 50 to 4999 kW (kW)
- Unmetered Scattered Load (kWh)
- Street Lighting (kW).

Table 7 of the OEB LRAMVA work form shows the percentage allocation by rate class for 2011 results and adjustments. Table 8 of the OEB LRAMVA work form shows the percentage allocation by rate class for 2012 results and adjustments. Table 9 of the OEB LRAMVA work form shows the percentage allocation by rate class for 2013 results and adjustments. Table 10 of the OEB LRAMVA work form shows the percentage allocation by rate class for 2014 results. Table 11-a of the OEB LRAMVA work form shows the percentage allocation by rate class for 2015 results. In each year the rate class allocation percentage totals for each program may not add up to 100% in cases were kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW.

Load reductions accounted for in the load forecast

BHI's last cost of service application was filed for the 2014 rate year (EB-2013-0115). The load forecast associated with that application accounted for load losses from 2011 – 2014 CDM programs. The forecast used actual load data up to 2013, so impacts of 2011 and 2012 are captured in the forecast. For 2013, because the projects are rolled-out throughout the year, only part of the savings that the IESO reported for 2013 would be captured though use of actual load data. Based on the half year rule, these are estimated at half the IESO reported savings.

The forecast also included a manual adjustment for half of estimated 2014 savings. Because the IESO reports results for a full year of savings, but only half of these would be realized in 2014, these estimates are doubled for comparison to the IESO results reported for 2014. Thus the amount assumed to be captured already through the load forecast is as shown below:

Rate class	Units	2013 results reported by the IESO	2014 manual adjustment	Total amount to compare to calculated lost revenues
Residential	kWh	1,642,521	1,591,117	4,003,495
GS < 50 kW	kWh	5,376,385	499,414	3,687,020
GS 50 to 4999 kW	kW	5,569	7,042	16,868
Unmetered Scattered Load	kWh	0	9,055	18,109
Street Lighting	kW	0	88	175

Table 3 of the OEB LRAMVA work form shows these estimates of load reductions, by rate class.

BHI's previous cost of service application was filed for the 2010 rate year (EB-2009-0259). The load forecast associated with that application did not account for load losses from 2011 – 2014 CDM programs.

Overall impact of CDM on load, by rate class

Multiplying the adjusted energy savings or demand reduction reported for BHI for each program by the allocation by rate class provides the impact on load of that CDM program within the appropriate rate class. The sum of the energy savings and demand reductions for all of the programs for each rate class provides the overall impact of CDM on load by rate class. The overall load impact for each calendar year includes the results for the CDM programs and any adjustments to the results in that year.

The bottom of Table 7 of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2011. The bottom of Table 8 of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2012. The bottom of Table 9 of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2013. The bottom of Table 10 of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2014. The bottom of Table 11-a of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2015.

Distribution rates

The distribution rates that are used to calculate the CDM impact on distributor revenue for each rate class for BHI are shown in Table 5 of the OEB LRAMVA work form. The distribution rates are pro-rated from the rate year to the calendar year, as needed, using the number of months of each rate year in each calendar year in the 2012 to 2016 time period. Table 6 of the OEB LRAMVA work form shows the pro-rated rates used for each calendar year. The values for 2011 and 2012

have been removed, since LRAMVA for these years has already been recovered.

Lost revenues

The lost revenues for each year by rate class for BHI calculated from final CDM program results are shown in Table 1 of the OEB LRAMVA work form. The lost revenue for each year is based on the load impact for each rate class in that year multiplied by the rate for that rate class in that year. The load impact in a given year will include the impact of CDM programs in that year and the persistence of the CDM program impact from previous years in that year.

The lost revenue for 2011-2015 is based on final verified results provided by the IESO.

Table 1 of the OEB LRAMVA work form also shows the lost revenue in each year due to CDM that has already been incorporated into BHI's applicable load forecast. The impact on BHI's revenue is the variance between what is calculated from final CDM program results and what has already been accounted for in the load forecast.

In BHI's 2014 COS rate case (EB-2013-0115), disposition of the 2011 to 2012 lost revenue amounts in Account 1568 was approved. The lost revenue from 2011 to 2012 CDM programs in 2011 and 2012 thus have not been included in the calculations in Table 1.

Carrying charges

The monthly carrying charges by rate class on BHI's lost revenue variance are shown in Table 15 of the OEB LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues resulted, through to April 30, 2017.

Carrying charges are calculated only for CDM results not previously disposed of.

Conclusions

The LRAMVA balance at the end of December 2015 for BHI that includes results from 2013 – 2015 CDM programs and adjustments to 2013 results is $499,068.50. The total carrying charges on this LRAMVA balance accumulated to April 30, 2017 are 18,904.04. These balances are attributable to individual rate classes according to the following table:

Rate class	LRAMVA	Carrying charges	Total
Residential	$187,482.54	$6,528.61	$194,011.15
GS<50	$211,001.38	$7,206.55	$218,207.92
GS 50 to 4,999	$102,736.58	$4,416.14	$107,152.72
Unmetered Scattered Load	($624.76)	($16.68)	($641.44)
Street Lighting	($1,527.23)	($40.58)	($1,567.82)
Totals	**$499,068.50**	**$18,094.04**	**$517,162.54**

Where negative values are shown, that indicates that the actual reduction in load from CDM programs was less than the amount included in the load forecast.

providing environmental and energy consulting
to private, public and non-governmental organizations

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Appendix B
Burlington Official Plan – February 2018
Schedules B and B-1

Burlington Official Plan

Proposed - February 2018

GROW BOLD

CITY OF
Burlington

Parkway Belt West Plan

e) The Provincial Parkway Belt West Plan is intended to provide for a multi-purpose *utility* corridor and linked open space system, which extends from the City of Hamilton through the Regions of Halton, Peel and York. The boundaries of the Parkway Belt West Plan Area are shown on Schedule A-1: Provincial Land Use Plans and Designations, of this Plan.

2.2.4 POPULATION AND EMPLOYMENT DISTRIBUTION

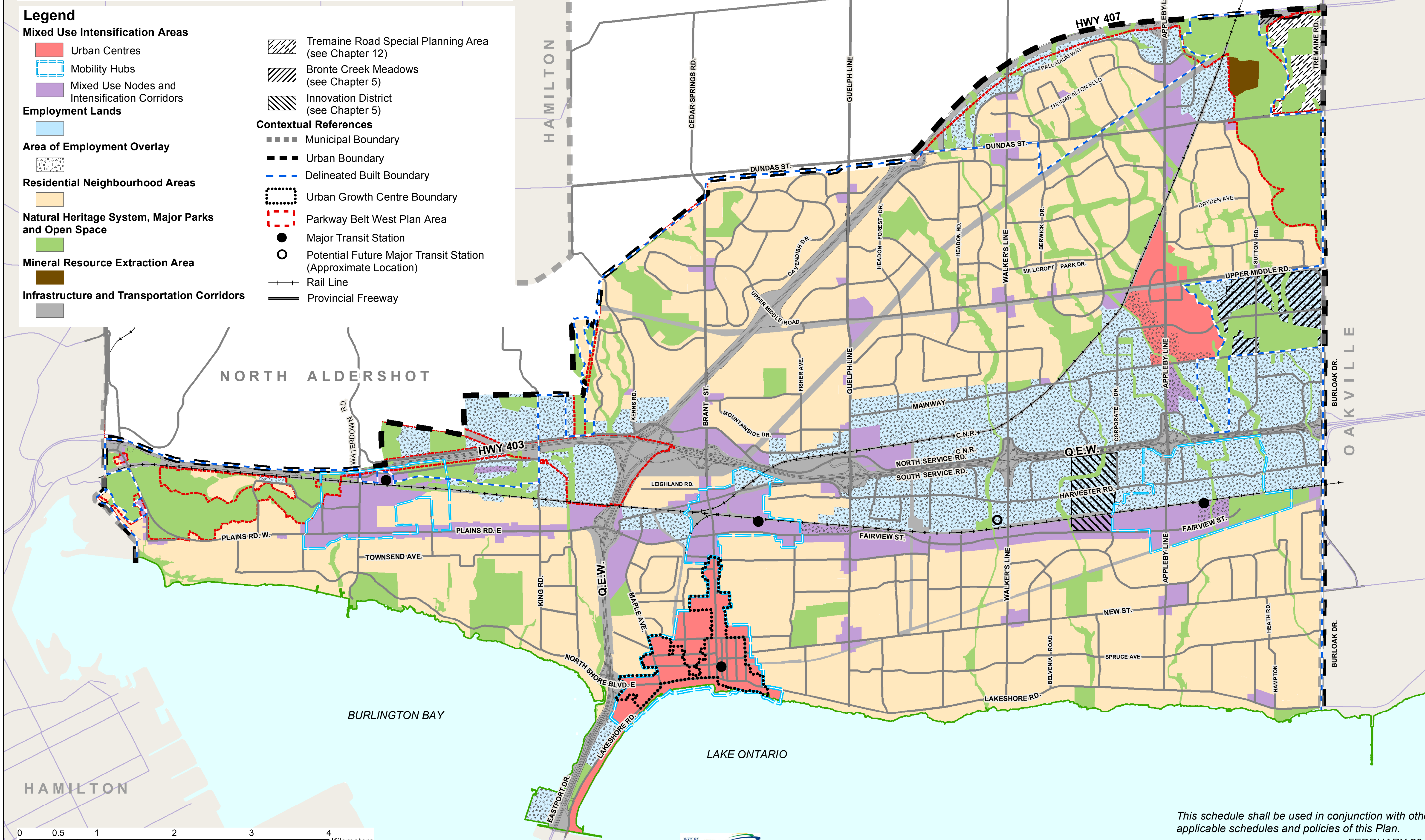
The Regional Official Plan established a growth strategy for the Region of Halton based on the distribution of population and *employment* to 2031 (Table 1: Population and Employment Distribution, of the Regional Plan). This distribution of population and *employment shall* be accommodated based on the policies of Table 2: Intensification and Density Targets, and Table 2A: Regional Phasing, of the Regional Official Plan.

Population*		Employment	
2006	**2031**	**2006**	**2031**
171,000	193,000	88,000	106,000

*Population numbers are “total population” numbers including approximately 4% under coverage from the official “Census Population” numbers reported by Statistics Canada.

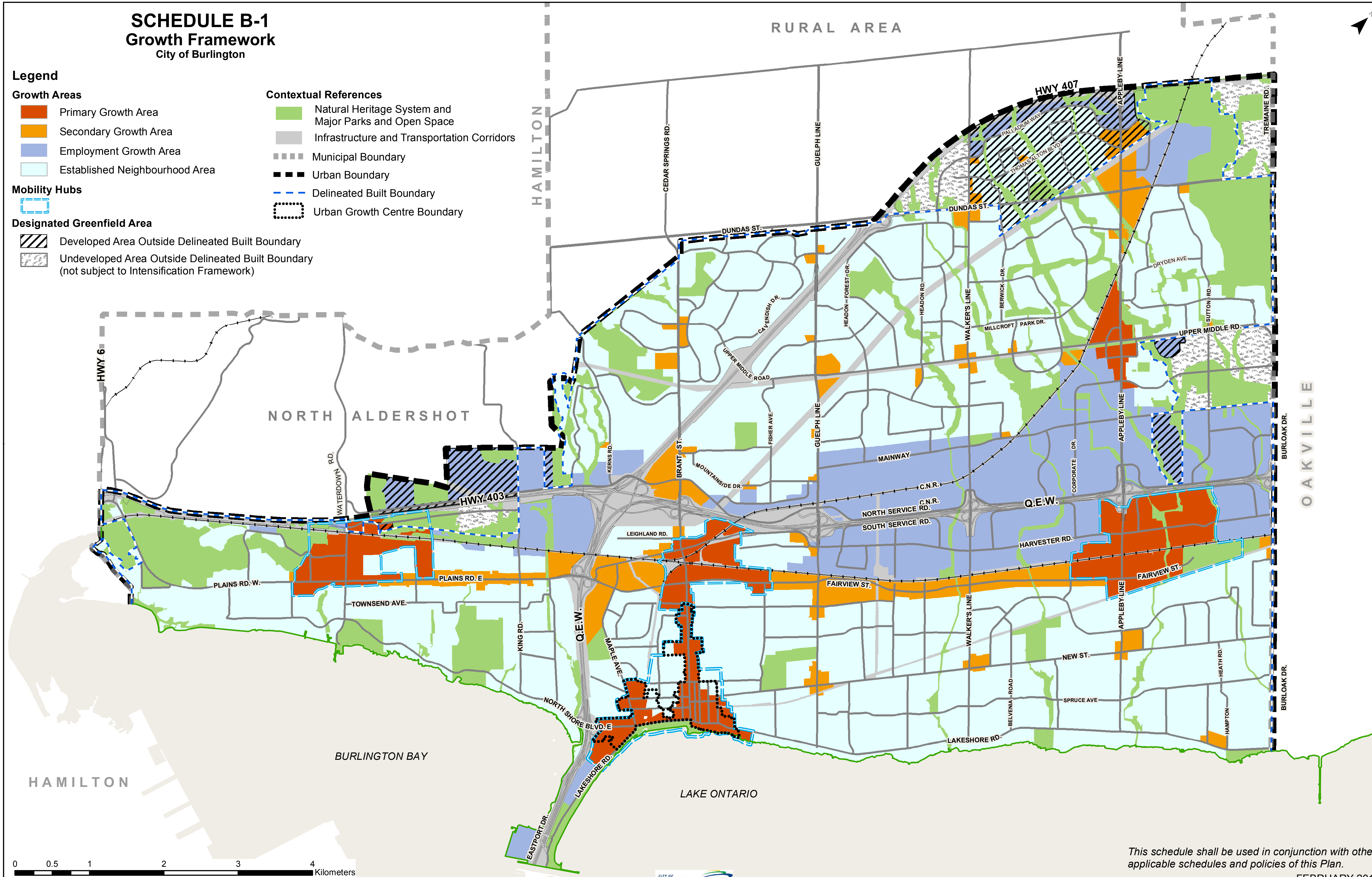
The population and employment forecasts are premised on the adequacy of *infrastructure* and *public service facilities* to support growth in appropriate locations. This Plan will require *infrastructure,* associated services, and *public service facilities*, to support the comprehensive implementation of this Plan.

SCHEDULE B
Urban Structure
City of Burlington



This schedule shall be used in conjunction with other applicable schedules and policies of this Plan.

FEBRUARY 2018


SCHEDULE B-1
Growth Framework
City of Burlington
Legend
Growth Areas
Primary Growth Area
Secondary Growth Area
Employment Growth Area
Established Neighbourhood Area
Mobility Hubs
Designated Greenfield Area
Developed Area Outside Delineated Built Boundary
Undeveloped Area Outside Delineated Built Boundary
(not subject to Intensification Framework)
Contextual References
Natural Heritage System and
Major Parks and Open Space
Infrastructure and Transportation Corridors
Municipal Boundary
Urban Boundary
Delineated Built Boundary
Urban Growth Centre Boundary
RURAL AREA
HAMILTON
NORTH ALDERSHOT
OAKVILLE
BURLINGTON BAY
LAKE ONTARIO
HWY 407
HWY 403
HWY 6
Q.E.W.
DUNDAS ST.
UPPER MIDDLE RD.
UPPER MIDDLE ROAD
CEDAR SPRINGS RD.
GUELPH LINE
WALKER'S LINE
APPLEBY LINE
TREMAINE RD.
BURLOAK DR.
BRANT ST.
WATERDOWN RD.
KING RD.
MAPLE AVE.
EASTPORT DR.
LAKESHORE RD.
NORTH SHORE BLVD. E
PLAINS RD. W.
PLAINS RD. E
TOWNSEND AVE.
LEIGHLAND RD.
FAIRVIEW ST.
HARVESTER RD.
NORTH SERVICE RD.
SOUTH SERVICE RD.
C.N.R.
MAINWAY
MOUNTAINSIDE DR.
KERNS RD.
FISHER AVE.
CAVENDISH DR.
HEADON FOREST DR.
HEADON RD.
BERWICK DR.
MILLCROFT PARK DR.
PALLADIUM WAY
THOMAS ALTON BLVD
DRYDEN AVE
SUTTON RD.
CORPORATE DR.
NEW ST.
SPRUCE AVE
BELVENIA ROAD
HEATH RD.
HAMPTON
0 0.5 1 2 3 4 Kilometers
This schedule shall be used in conjunction with other applicable schedules and policies of this Plan.
FEBRUARY 2018
City of Burlington

Appendix C
Burlington Hydro's Overtime Policy

HR195

Overtime

for

Management/Non-Union

Date: January 2018 – V.1

Issued by: Sharon Goodwin,
Manager, Human Resources

Approved by: Jennifer Smith,
VP, Corporate Relations

Review Schedule - **Annual**

Table of Contents

1.0 Introduction

Burlington Hydro Electric Inc. (BHEI or the Company) provides eligible salaried employees overtime determined by situation and circumstances. Considerations are given to the situation, the length and necessity of the overtime and the consistency with company practice.

2.0 Policy Scope

This Policy applies to all salaried employees (management and non-union). Overtime provisions for Union employees are governed by the terms of the Collective Agreement.

3.0 Overtime Eligibility for Salaried Employees

Due to the nature of their positions, Trades Supervisors from time to time are required to work overtime.

All other salaried employees who perform professional/management/supervisor/leadership functions primarily are generally exempt from overtime.

4.0 When Overtime is Acceptable

Eligible employees are only entitled to overtime wages for work that is requested, acknowledged or authorized by the employer. Burlington Hydro Inc. provides eligible employees overtime pay only when it involves planned overtime, overtime for projects with strict timelines that require work to be completed in a condensed period of time, after-hour emergencies or extenuating circumstances. Overtime will **not** be authorized for administrative work.

Meal Allowances do not apply to non-unionized employees. Expense meals as appropriate with relevant Business Expense (HR110).

5.0 Time Management

All salaried employees are expected to manage workload effectively and delegate appropriately to meet their objectives and work targets. Employees are expected to identify staffing and training/development opportunities to their Departmental Head.

6.0 Extraordinary Efforts

When extraordinary after-hour individual efforts/contributions by salaried employees have been identified by their departments, time-off or a special bonus may be considered as approved by VP, Corporate Relations and CEO.

7.0 Processing Overtime & Authorization

Employees are responsible to inform and/or obtain approval for all overtime work completed from their direct Manager. Overtime work, in excess of 40 hours per week, must be authorized by the Manager. Authorized overtime hours worked is paid at the rate of two (2) times the employee’s base hourly rate.

8.0 Compliance

Compliance with the provisions and expectations of this Policy is an essential element in the Company's business success. Managers/Supervisors are responsible for ensuring the provisions of this Policy are communicated to, understood and observed by all employees. Failure to conduct oneself in accordance with this Policy will result in the individual(s) being subject to appropriate corrective action, which may include, where appropriate, disciplinary action, up to and including termination.

9.0 Inquiries

For further information regarding this policy, contact Human Resources.

10.0 Supporting Policies

Employees are expected to understand, follow align his/her obligations under all relevant policies.

- Business Expenses (HR110)