CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

November 4, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: 2017 ELECTRICITY DISTRIBUTION RATE APPLICATION FOR CANADIAN NIAGARA POWER INC., ("CNPI") EB-2016-0061
RESPONSE TO UNDERTAKINGS

Please find accompanying this letter, two (2) copies of CNPI's responses to Undertakings arising from the Technical Conference. Co-incidentally with the submission, an electronic copy of these responses along with requested Excel Worksheets have been filed via the Board's Regulatory Electronic Submission System.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 871-0330 extension 3278.

Yours truly,

Original Signed By:

Gregory Beharriell, P. Eng.
Manager Regulatory Affairs

Enclosure

UNDERTAKING NO. JTC1.1: TO PROVIDE AN UPDATED AND CORRECTED REVENUE-REQUIREMENT WORK FORM THAT REFLECTS THE DIFFERENT ITEMS LISTED; ALSO, TO UPDATE THE COST OF CAPITAL PARAMETERS THAT CAME OUT LAST WEEK; ALSO, FOR EVERY ITEM LISTED IN ENERGY PROBE'S LIST OF QUESTIONS, TO PROVIDE ANY CLARIFICATION REQUIRED.

Response:

An updated RRWF model has been provided, along with the following written clarifications to the 1-Energy Probe-22 questions submitted in advance of the Technical Conference.

1-Energy Probe-22

a) Please explain why the grossed up revenue deficiency shown on line 4 in the Tracking Form of $2,359,629 is different than the gross revenue deficiency shown in the Revenue Deficiency/Sufficiency sheet of $2,125,212.

- Line 4 in the Tracking Form was showing the impact of the revised load forecast on the cost of power only.
- The correct Distribution Revenue at Current Rates resulting from the new load forecast was input on the Data Input Sheet, but the resulting change to the Revenue Deficiency/Sufficiency was not then carried to the Tracking Form.
- A line has been added to the Tracking Form to reflect the change in Revenue Deficiency/Sufficiency due to increased revenue resulting from the updated load forecast.

b) Where in the tracking form has the change in distribution revenue based on the new load forecast at existing rates been reflected?

- The change in revenue at existing rates based on new load forecast is reflected in references 5 and 6 on the Tracking Form tab.

c) On the Tracking Form, please explain why for each of lines 1 through 4 that reflect the changes made as a result of the interrogatory responses, the change in the grossed up revenue deficiency is not equal to the change in the base revenue requirement and service revenue requirement.

- In the previously filed RRWF, all tax changes and the formula impact identified in d) were grouped on Line 1 of the Tracking Sheet.
- As a result, differences on Lines 2-4 were net vs gross amounts.
- This has been changed in the revised RRWF filed with Technical Conference undertakings.

d) Please explain why in the Revenue Deficiency/Sufficiency sheet, some of the figures are different in the Initial Application columns from that filed in the original RRWF. For example, the original RRWF showed a gross revenue deficiency of $2,316,325, while the updated RRWD shows a gross revenue deficiency of $2,441,458.

- A change in formula in cell F34 of Tab 8 of the 2017 RRWF model now defaults to 0 if no tax is payable.
- This change affects several other cells that reference the deficiency/sufficiency
- There is no impact on revenue requirement or rates
- A new Line 1 has been inserted in the Tracking sheet to reconcile the 2017 Model calculation to the value in the 2016 Model from initial filing.

e) Please explain why distribution revenues at proposed rates are lower than distribution revenues at existing rates in the Initial Application columns in the Revenue Deficiency/Sufficiency sheet.

- Distribution revenues at proposed rates are higher than distribution revenues at existing rates, however Cell H20 on the Revenue

Deficiency/Sufficiency sheet displays the distribution revenue at proposed rates less the revenue deficiency at existing rates shown in Cell H19

- Adding H19+H20 = 19,870,307, equal to the revenue at Proposed rates in Cell E26 of Data Input Sheet

f) Please confirm that the difference noted in part (e) is why the Application gross revenue deficiency figures provided in the Summary Table at the bottom of the Revenue Requirement sheet do not match.

- Not confirmed – the Summary Table is an addition to 2017 Model – it compares Deficiency/Sufficiency to the difference between Distribution Revenue at proposed and existing rates (all else being equal revenue from rates should have to increase by the amount of the grossed-up deficiency)
- The difference in the Initial Application numbers seems to relate primarily to the issue in d) above (change in the formula for treatment of negative taxable income)

g) Please provide an updated RRWF that reflects any changes or corrections as a result of the above questions.

- An updated RRWF has been filed in conjunction with these written responses. In addition to any changes in response to 1-EP-22, the updated RRWF also reflects any updates required based on other technical conference responses.

UNDERTAKING NO. JTC1.2: TO CLARIFY WHAT KILOWATT-HOUR GROUPS 1, 2, AND 3 ARE ON THE CHART; ALSO TO PROVIDE THE FEASIBILITY OF CONDUCTING A SURVEY BY SERVICE AREA IN THE FUTURE.

Response:

The kWh groups 1, 2 and 3, represent a grouping of all survey respondents based on differences in average monthly kWh consumption. Group 1 includes customers in the lowest 25% of consumption, Group 2 includes customers in the middle 50% of consumption, and Group 3 includes customers in the highest 25% of consumption.

CNPI has determined that while it would be feasible to conduct future surveys by service area, the minimum cost per additional survey would be $10,000.

UNDERTAKING NO. JTC1.3: TO SHOW THE CALCULATION OF THE 1.139 MILLION IN REVENUES BASED ON THE NET BOOK VALUE AND THE DEPRECIATION VALUES SHOWN IN RESPONSE TO PART (D) OF 3 ENERGY PROBE 13, BUT THIS TIME INCLUDING TAXES

Response:

Please see table below for calculation of revised 4375 revenue. The decrease has been reflected in the updated RRWF as provided in JTC 1.1.

Calculation of Revised Revenue in 4375		
2017 Depreciation	848,465	**A, NOTE 1**
2017 Average Net Book Value	3,509,652	**B, NOTE 1**
Revised WACC per JTC1.1	6.84%	**C**
Return on Assets	240,060	**D = B * C**
Calculation of Taxes:		
Equity	40%	**E**
Revised ROE per JTC1.1	8.78%	**F**
Tax Rate	26.5%	**G**
Taxes	32,664	**H = B * E * F * G**
Grossed Up Taxes	44,440	**I = H / (1 - G)**
Revised 4375 Revenue	**1,132,965**	**J = A + D + I**
Original 4375 Revenue per Application	**1,139,217**	
Difference	**(6,252)**	

NOTE 1: The above reflects only the portion of the shared assets that would otherwise be allocated to the related parties (i.e. the portion used to generated the revenue in 4375). Balance was adjusted to reflect 2016 IT SAP capex reductions noted in 2-EP-5.

UNDERTAKING NO. JTC 1.4: TO PROVIDE A CALCULATION OF THE TAX IMPACT FOR REVENUES FROM GPI AND WESTARIO

Response:

Please see table below for calculation of revised calculation of Assets and Depreciation underpinning the Asset Utilization portion of the 2017 Fees for Service in OEB 4325.

Calculation of Revised Asset Utilization Portion of Revenue in 4325		
2017 Estimated Depreciation	133,000	**A, NOTE 1**
2017 Estimated Average Net Book Value	633,000	**B, NOTE 1**
Revised WACC per JTC1.1	6.84%	**C**
Return on Assets	43,000	**D = B * C**
Calculation of Taxes:		
Equity	40%	**E**
Revised ROE per JTC1.1	8.78%	**F**
Tax Rate	26.5%	**G**
Taxes	5,891	**H = B * E * F * G**
Grossed Up Taxes	8,000	**I = H / (1 - G)**
Revised 4325 Revenue	**184,000**	**J = A + D + I**
Original 4325 Revenue per Application	**181,000**	
Difference	**3,000**	

NOTE 1: The above reflects only the portion of the NBV and depreciation related to the Asset Utilization fees to be billed to the associates in 2017.

UNDERTAKING NO. JTC1.5: TO GO BACK AND SEE WHETHER THERE WERE ANY OTHER PROVINCIAL-WIDE ECONOMIC INDICATORS SUCH AS GDP THAT MIGHT BE A BETTER INDICATOR THAN USING EMPLOYMENT ON A PROVINCE-WIDE BASIS.

Response:

CNPI confirmed with Elenchus that use of GDP could be considered a statistically valid alternative to the use of province-wide employment. Some statistical parameters become marginally better in the GDP model than with the province-wide employment model, though the parameters were already quite strong in the province-wide employment model. The overall impact of using the GDP model would be a reduction in 2017 forecasted load of approximately 0.76% as compared to the model filed in conjunction with CNPI's IR responses.

UNDERTAKING NO. JTC1.6: TO LOOK AT THE CONTRIBUTIONS AND THINK THROUGH THE LOGIC OF THE CONTRIBUTION.

RESPONSE:

Pensions	2009 to 2011	2012	2013	2014	2015	2016	2017
Pension expense (000's):							
OM&A	$ 934	$ 276	$ 344	$ 284	$ 245	$ 97	$ 211
Related parties through shared service agreements	$ 199	$ 92	$ 98	$ 98	$ 108	$ 44	$ 86
Capital (added to rate base)	$ 470	$ 141	$ 176	$ 138	$ 154	$ 63	$ 133
Total actual pension expense	$ 1,602	$ 509	$ 618	$ 520	$ 507	$ 204	$ 431
less: Shared sevices	$ (199)	$ (92)	$ (98)	$ (98)	$ (108)	$ (44)	$ (86)
Pension expense included in OM&A and for Capital	$ 1,403	$ 417	$ 520	$ 422	$ 399	$ 160	$ 344
Paid contributions (cash) [1]	$ 2,578	$ 1,111	$ 1,126	$ 1,120	$ 626	$ -	$ -
Net difference	$ (1,175)	$ (694)	$ (606)	$ (698)	$ (227)	$ 160	$ 344

OPEBs	2009 to 2011	2012	2013	2014	2015	2016	2017
OPEB expense (000's):							
OM&A	$ 695	$ 251	$ 251	$ 257	$ 286	$ 295	$ 276
Related parties through shared service agreements	$ 148	$ 84	$ 72	$ 89	$ 126	$ 133	$ 113
Capital (added to rate base)	$ 350	$ 128	$ 129	$ 125	$ 180	$ 193	$ 174
Total actual OPEB expense	$ 1,193	$ 463	$ 452	$ 471	$ 592	$ 621	$ 563
less: Shared sevices	$ (148)	$ (84)	$ (72)	$ (89)	$ (126)	$ (133)	$ (113)
OPEB expense included in OM&A and for Capital	$ 1,045	$ 379	$ 380	$ 382	$ 466	$ 488	$ 450
Paid benefit amounts (cash)	$ 762	$ 310	$ 317	$ 291	$ 295	$ 290	$ 306
Net difference	$ 283	$ 69	$ 63	$ 91	$ 171	$ 198	$ 144

The above schedules are not reflective of amounts historically included in distribution rates as no annual re-basing has been completed to reflect changes in actual Pension and OPEB expenses. As well, only a portion of the amounts added to capital are collected annually through distribution rates. These schedules highlight the difference between pension/OPEB accruals recognized by CNPI and cash payments. These amounts are not definitively correlated to distribution rates.

1. Paid contributions are primarily determined by actuarial valuations as prepared by Mercers. The Actuarial Valuation is used to determine the minimum required funding contributions in accordance with the Pension Benefits Act. No methodology has been determined to allocate between operating, capital and shared services, nor between active and inactive employees.

UNDERTAKING NO. JTC1.7: LOOK INTO THE IMPACT OF THE MARGIN OF DEVIATION ON THE TEST YEAR REVENUE REQUIREMENT, IF ANY

Response:

In our response to 4-Staff-75, it was stated that "the impact of the going concern discount rate is limited to it's impact on the current service cost." As clarified with our actuary, this would be true if our expense for regulatory purposes was in fact calculated per the requirements of Section 3462 of the CPA Handbook where the discount rate to determine expense would be the Funding discount rate. The expense under 3461, as currently used by CNPI for regulatory purposes, uses a discount rate that is not tied to the Funding Valuation rate, but rather a market discount rate (as referred to in response to 4-Staff 73) that changes annually for accounting valuation purposes. The rate of 3.90% is the applicable rate used for calculating the Test Year pension expense.

Therefore, the impact of the margin for adverse deviations on the Test Year Revenue Requirement is nil.

UNDERTAKING NO. JTC1.8: TO PROVIDE THE NUMBER OF CUSTOMER DISCONNECTIONS FROM EACH YEAR, 2013 TO 2017.

Response:

The table below are the residential disconnections from 2013-2017.

The 2016 projected disconnections are based on YTD totals and 2017 is estimated to increase the same percentage as the 2015 to 2016 increase.

Canadian Niagara Power

Disconnections 2013-2017

Year	Total	
2013	524	
2014	462	
2015	399	
2016	447	Projected
2017	501	Projected

Note: 2015 October YTD 347

2016 October YTD 372

UNDERTAKING NO. JTC1.9: TO REFILE 4 STAFF 83 WITH ATTACHMENT.

Response:

Please find attached a complete interrogatory response to 4-Staff-83 with the attachment.

4-Staff-83

Ref: E4/T11/S1/p. 1 & CNPI July 13, 2016 *Response,* item 11 & Ontario Energy Board *Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017* *Rate Applications Chapter 2,* July 14, 2016, p.39.

The first reference above is a very high level one-page summary of CNPI's depreciation policy included in its original filing.

The second reference is CNPI's response to the OEB's incomplete letter of June 30, 2016 which had noted that one of the deficiencies of CNPI's application as filed was that only a "One page summary of depreciation policy is provided with no discussion of changes since CNPI's last cost of service application." CNPI's response to this deficiency was to refer the OEB back to the one-page depreciation summary that had been referenced in the OEB's deficiency letter and to state that it had not made any changes to the depreciation policy since the last cost of service application.

The third reference, which is the Filing Requirements, states that "The applicant must provide a copy of its depreciation/amortization policy. If not, the applicant must provide a written description of the depreciation practices followed and used in preparing the application."

Please state whether or not CNPI has a depreciation/amortization policy document of the kind referenced in the Filing Requirements. If yes, please provide this document or explain why it has not been provided. If no, please explain why not and state whether or not the one-page summary contained in the first reference is the extent of CNPI's depreciation practices followed and used in preparing the application. If not, and in the absence of a policy document, please provide a complete written description of the depreciation practices followed and used in preparing the application.

RESPONSE:

The extent of CNPI's written policy regarding componentization and depreciation accounting policy was provided in Exhibit 11, Tab 1, Schedule 3, Appendix B of CNPI's 2013 EDR. A copy of this policy has been provided within this interrogatory response for ease of reference. CNPI does not have any additional comprehensive written documentation regarding its depreciation/amortization (herein referred to as "depreciation") policy. CNPI relies upon the experience and qualifications of the personnel within the Finance department responsible for the management of the accounting of assets, including the calculation of depreciation. CNPI also follows the guidelines set out by the Ontario Energy Board. Some additional explanation regarding the depreciation practises is provided below.

Depreciation calculation commences once an asset is deemed to be used and useful. The calculation of monthly depreciation for reporting purposes is automated; a module within the accounting system (SAP) is run and financial postings are generated. Depreciation is calculated on a straight-line basis. For the purposes of this rate proceeding, the calculation of the 2017 Test Year depreciation was a combination of manual and automated calculations. The output of a depreciation simulation module within the accounting system was used first to calculate the forecasted 2017 depreciation expense on existing used and useful assets. Then, a manual calculation was added to this value in consideration of the expected used and useful additions in 2016 and 2017. A full year of depreciation was calculated in 2017 for 2016 additions while a half year rule was used for any 2017 additions.

As stated within Exhibit 4, Tab 11, Schedule 1 of this Application, the Board's Kinectrics Report had been used as a guideline to update the depreciation rates in CNPI's 2013 EDR, and those are the same rates that have been used in the calculation of the 2017 Test Year depreciation within this Application.

As part of the accounting changes effective January 1, 2013, implemented in CNPI's 2013 EDR, vehicle depreciation is now being included in the burden rates. Similar to the depreciation process outlined above, vehicle depreciation expense is simulated automatically, using the accounting system, on a monthly basis. For the purposes of this rate proceeding, the calculation of the 2017 Test Year vehicle depreciation was a combination of manual and automated calculations. The output of a depreciation simulation module within the accounting system was used first to calculate the forecasted 2017 vehicle depreciation expense on existing used and useful assets. Then, a manual calculation was added to this value in consideration of the expected vehicle additions in 2016 and 2017. A full year of depreciation was calculated in 2017 for 2016 additions while a half year rule was used for any 2017 additions.

APPENDIX B

Componentization and Depreciation Accounting Policy Update

Standard: Property, Plant and Equipment

Topic: Componentization and Depreciation

Conclusion Document

Objective:

To document the accounting policy on componentization and depreciation of property, plant and equipment in compliance with International Financial Reporting Standards ("IFRS") IAS 16 for the Fort Erie, Eastern Ontario Power and Port Colborne business units.

Background:

Each part of an item of property, plant and equipment ("PP&E") with a cost that is significant in relation to the total cost of the item will be depreciated separately.

The company will allocate the amount initially recognized in respect of an item of PP&E to its significant parts to be depreciated separately.

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

Depreciation is to be computed on a systematic basis over the estimated useful life of the item of PP&E. The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance section 1506 *Accounting Changes* of the Accounting Standards for Private Enterprises ("ASPE").

Depreciation of an asset begins when it is available for use (i.e., when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with **IFRS 5** and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted in compliance with IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense under IFRS, are set out in Table 1 attached.

Overhead System

Four components have been identified – overhead pole – fully dressed, overhead conductor and devices, transformers, and services cable. All overhead assets purchased after January 1, 2011 will be classified into one of these four components.

Overhead pole – fully dressed:

A fully dressed pole is defined to include the pole itself, cross arms, insulators and guy wires. The company currently has a useful life of 25 years for poles, the majority of which are wood. A limited number of concrete, composite fiber glass and steel poles are in use in the system however these are not significant. One component will be used for poles regardless of type of pole.

Mechanical stress ("MC") is caused from spans of > 50 metres. Most pole spans in the system average < 50 metres and are even shorter in the urban environments, therefore the system has average MC. However, lake effect weather increases the MC, so MC stress in the system averages out to high, which is similar to the Kinectrics factor for typical useful life. The useful life of the pole is therefore 45 years (Kinectrics typical useful life). The pole is often in use for closer to 50 years due to the rate of replacement. Other parts on the fully dressed poles, such as cross arms and insulators, have useful lives that range from 40-50 years and the life is often less than 45 years. Therefore a useful life of 45 years for a fully dressed pole is appropriate.

Overhead Conductor and Devices:

The company currently uses a useful life of 33 years. The company's current operating practice for the overhead systems has been to replace the conductor when changing the pole.

As discussed above, MC in the company's system is high. The system has lower electrical loads ("EL") but the EL in the system is not low. It is not high either as compared to other utilities. The Kinectrics report has identified EL as low in order to achieve typical useful life. Historically the company has had higher environmental conditions ("EN"), but that is no longer the case. The Kinectrics report has EN set as moderate to achieve typical useful life. The company's policy is to replace the conductor at the same time as the pole; therefore, the conductor has a similar life as that of the pole. Therefore, a useful life of 45 years has been set for conductor.

Devices in the system include field control devices, line switches and RTUs. Line devices are not significant in dollar value nor do they have a significantly different useful life compared to the conductor to which they are attached.

Field control devices have a much lower life than conductors. These devices have an approximate life span of 25 years; devices are replaced on a one on one basis as they fail.

There are only a few line switch RTU's in the system (one per substation). They are currently being replaced with a modern version because of technological obsolescence. As a result of technological obsolescence RTUs will become obsolete after 10 years. These are not a significant dollar value to warrant separating out as its own component.

Therefore, devices will be grouped with conductor and given the same useful life of 45 years.

Transformers

The company currently does not separate padmount transformers from overhead transformers. The padmount transformers are not a significant portion of the general ledger balance for transformers (10-20% of the balance in the transformer account). Underground transformers are used for any new development, which is required by the city by-law. For future acquisitions, the company will set up a separate asset class for padmount transformers.

MC is low on average. Older areas of the system have higher EL but in other areas, EL is average. From an environmental point of view, the main concern is lightning strikes; however, the company does not have an unusual loss from lightning strikes, therefore, EN is average. Utilization factors are consistent with the typical factors to achieve typical useful life identified in the Kinectrics report. The company's policy is to run the transformer to failure. Therefore, the typical useful life of 40 years for transformers is appropriate. The expectation is that when the company rebuilds the underground system, the new pad mount in the subdivision would last 30 years, possibly 35, which is closer to the life of the overhead transformer, such that setting the useful life of underground transformers at 40 years is reasonable. Kinectrics typical useful life for underground padmounted transformers is 40 years as well.

Services Cable

The majority of the balance for service wire in the general ledger is underground and it will be in the future as well. The typical useful life for underground service in duct is 40 years and the actual utilization factors do not differ from the typical factors identified by Kinectrics. The current system has not yet been in place for 40 years, so the company does not have actual experiential data to determine the useful life. Therefore, the Kinetrcis typical useful life of 40 years will be used to depreciate service wire.

Underground System

Three components of the underground system have been identified – cable and devices, conduit, service cable.

Cable and Devices

Cable in the older parts of the system is non TR XLPE, direct buried most of which is fully depreciated, whereas new installations are TR XLPE, in duct. The system has lower EL but it is not low and it is not high. The utilization factors experienced in the system do not differ significantly from the typical factors identified by Kinectrics. The typical useful life identified by Kinectrics is 40 years. As the conditions in the system do not vary from the utilization factors identified by Kinectrics, a useful life of 40 years will be used to depreciate cable and devices.

Service Cable

See "Service Cable" under overhead systems.

Conduit

Conduit includes foundations, vaults, ducts and cable chambers. Conditions in the system do not vary from the utilization factors identified by Kinectrics. Useful life of 50 years is to be used to depreciate conduit assets.

SCADA

The company currently uses a useful life of 10 years. The typical useful life identified by the Kinectrics report of 20 years is reasonable. The biggest factor that affects SCADA is technology, and the SCADA equipment could be obsolete sooner than 20 years. However, the company's policy does not provide for replacement just because technology changes. The company's replacement program is replacing SCADA equipment at around 20 years of life. When installed, SCADA equipment is expected to have a 20 year life. Therefore, the useful life will be 20 years. It should be noted that computer hardware responsible for running the SCADA application would typically not be warrantied for more than five years, which is in line with the useful life associated with any non-SCADA computer hardware (see Hardware section).

Meters

Meters consist of smart meters, interval meters, CTs and PTs and stranded meters.

Smart meters are currently using a useful life of 25 years. The Kinectrics report identified the useful life of smart meters as between 5 and 15 years and the manufacturer is also suggesting a life of 15 years. Currently, the industry is using a range between 10 and 15 years for the useful life. Smart meters will be depreciated over a useful life of 15 years.

Currently, GS>50 (interval class) customer class meters have a useful life of 25 years and the CT & PTs are included with these meters. The Kinectrics report shows a range for useful lives for industrial/ commercial and wholesale meters of 25 to 35 years. For CT & PT meters, the Kinectrics report shows a useful life of 35 to 50 years. CT & PT meters are not a significant dollar value to segregate as a separate component with a separate useful life. An average of 30 years for the useful life will be applied to all meters, excluding Smart Meters.

Meters will be split into three separate accounts; smart, other and stranded so that each type can be depreciated over it useful life.

Station Equipment

Two components have been identified for station equipment: power transformers and switchgear/breakers. These components represent the significant dollar value components of a distribution station. These will be accounted for as separate components in the general ledger. There is no need to break out the power transformer into further components because of the lower dollar magnitude of those components. Stations have either breakers/switches or switchgear, however the company does have some that are a combination.

The general ledger currently includes power transformers, as well as other station equipment (such as switchgear, station switches) in the same account with a useful life of 33 years.

The company's maintenance policies and practices have been designed to provide 50 years of useful life from the station transformers. Currently, most station transformers are about 40 years old and not yet ready for replacement**.**

The system has lower electrical loading, however electrical loading is not low, nor is it high. The utilization factors do not differ from the typical identified by Kinectrics. Typical useful life is considered appropriate for the the switchgear/breakers at the Stations. All would have the same useful life of 40 years.

Given the maintenance practices and capital planning time frames associated with the power transformers, the useful life will be 50 years.

Station switches are not a significant dollar value and are to be depreciated over the same useful life as switchgear. There is no need to separate them out into a separate component.

Minor Assets

Equipment

The existing components for the minor assets are considered to be appropriate and are not significant in relation to the distribution system assets and fixed assets as a whole. The components are buildings and fixtures, transportation equipment, tools and shop & garage equipment, miscellaneous equipment, stores equipment, measurement & test equipment, power equipment, office equipment, computer software & hardware, easements and communication equipment.

Buildings and fixtures are currently using a useful life of 50 years. There is no need to change the useful life as it falls within the range that Kinectrics has stated. Buildings and fixtures will remain at the 50 year useful life.

For transportation equipment, the current practice is to turn in small vehicles after 175,000 km, which is roughly 5 years. Therefore, a useful life of 5 years will be used. For larger vehicles, such as trucks and buckets, it is typically 10 years before the company begins to think about replacing them. The truck along with the bucket have the same useful life since they are replaced at the same time since the residual value of the truck is not significant, a useful life of 10 years will be used.

The useful life of tools and shop and garage equipment will remain at 10 years, as will stores equipment, measurement and test equipment, power equipment and office equipment. Miscellaneous equipment will remain at a useful life of between 5 and 10 years depending on the equipment type. This is consistent with Kinectrics life ranges.

Software

Software consists of server, firewall, and Enterprise Microsoft applications and is currently being depreciated over a 10 year useful life. There are two main types of software; SAP software and minor software programs.

It is expected that SAP software will be upgraded/ replaced at a minimum of every 5 years; however, actual replacement is closer to 7 years between detailed upgrades. Between major revisions, 7 to 10 years can be obtained. SAP software life will remain at a useful life of 10 years.

Hardware

There is a cycle of 5 years for the replacement of hardware and desktop computers along with the related software. The company currently has a 5 year warranty. PC's and laptops will be combined and remain at a useful life of 5 years, including 5 years for the server. For minor software that is attached to the hardware, a useful life of 5 years will also be used.

For communication equipment, phones are an enterprise class product, which includes personal phones, PDA's, and two-way radios. Cell phones and smart phones, are usually purchased as disposable items and should be expensed rather than capitalized. The majority of the balance in the general ledger account relates to the two-way radio system, which has a current useful life of 20 years. The Kinectrics report has indentified a useful life of between 2 and 10 years. The useful life of communications equipment will be reduced to 10 years.

Phone systems have a long useful life however if the company takes advantage of new functions that become available, newer versions of the equipment are often needed in order to be compatible with the new functions. In the past, useful life has been 10 years, and that will continue to be used.

Easements

The cost of an easement is the cost of registering the property and it should be amortized over the life of the easement. Easement agreements are typically for a finite life of 40 years. Easements will be depreciated over the life of the agreement which is expected to be 40 years.

Conclusion:

The new levels of componentization and the corresponding useful lives will be applied with the approval by the OEB in accordance with standards for a change in accounting estimate in ASPE section 1506 *Accounting Changes*.

Table 1: PP&E Components and Estimated Useful Lives

FIXED ASSET COMPONENTS and ESTIMATED USEFUL LIVES				
Component	**Previous Component**	**Existing Useful Life**	**Kinectrics Guidelines**	**Proposed Useful Life**
Land	Land	-	N/A	-
Buildings & Fixtures	Buildings & Fixtures	50	50-75	50
Overhead Poles, fully dressed	Poles, Towers & Fixtures	25	35-75	45
Overhead Conductor & Devices (reclosers)	Overhead Conductor & Devices	33	C-50-75 D-25-55	45
Overhead Transformers	Line Transformers	33	30-60	40
Padmounted Transformers	Line Transformers	33	25-45	40
Underground Cable & Devices (direct buried)	Underground Conductor & Devices	33	25-35	40
Underground Service Cable (direct buried)	Services	33	25-40	40
Underground Conduit	Underground Conduit & Manholes	50	35-80 (1)	50
SCADA	System Supervisory Equipment	10	15-30	20
Smart Meters	Meters	15	5-15	15
Other Meters, PTs & CTs	Meters	33	35-50	30
Power Transformers	Station Equipment	33	30-60	50
Switchgear & Breakers	Station Equipment	33	30-65 (1)	40
Office Furniture and Equipment	Office Furniture and Equipment	10	5-15	10
Computer Equipment Hardware	Computer Hardware	5	3-5	5
Computer Software - SAP	Computer Software	10	N/A	10
Computer Software - Other	Computer Software	10	2-5	5
Small Vehicles	Transportation Equipment	5	5-10	5
Trucks & Buckets	Transportation Equipment	10	5-15	10
Tools, Shop, Garage Equipment	Tools, Shop, Garage Equipment	10	5-10	10
Measurement & Testing Equipment	Measurement & Testing Equipment	10	5-10	10
Stores Equipment	Stores Equipment	10	5-10	10
Power Operated Equipment	Power Operated Equipment	10	5-10	10
Miscellaneous Equipment	Miscellaneous Equipment	5-10	N/A	5-10
Communication Equipment	Communication Equipment	20	2-10	10
Easement	Land Rights	40	N/A	40

(1) Combination of a number of related categories in Kinectrics report.

UNDERTAKING NO. JTC1.10: TO LOOK AT THE TWO DOCUMENTS AND RECONCILE THE TWO DIFFERENCES AND CLARIFY WHERE THE NUMBERS IN THE BURMAN ENERGY REPORT ACTUALLY CAME FROM AND HOW THEY RELATE TO THE PERSISTENCE REPORT.

Response:

The example discrepancy discussed at the Technical conference related to the apparent discrepancy in the persistence of 2012 programs of approximately 1.1 million kWh according to the IESO Persistence Report, and approximately 1.6 million kWh according to the Burman Report.

Certain CDM projects and programs involve a lag between the actual implementation of a given project (i.e. when the energy or demand savings start), and the closing of the project for IESO reporting purposes (i.e. when the LDC receives credit for achieving CDM targets and the quantified savings are included in the Persistence Report). These delays can be caused by both administrative lag on the part of the customer, consultant, LDC and/or IESO and by the requirement for additional verification and measurement process required to quantify the actual energy/demand savings for certain types of projects. As a result of this lag, a portion of the projects implemented in any given year may be closed in future years, with the associated persistence impact being identified in future year persistence reports.

The reconciliation below includes the persistence associated with projects implemented in 2012, but closed in 2013 and 2014. Because the persistence shows up in future year reports, it must be added to the values obtained from the 2012 report in order to get to the approximately 1.6 million kWh values shown in the “Results from 2012 Total” line in the Burman Report. The remaining difference of approximately 560 kWh is equal to the line item in the 2012 IESO report that is shown as having a 2012 implementation date, but described as “Pre-2011 Programs Completed in 2011”, and was therefore appropriately excluded by Burman. While this example focuses on 2012, the same methodology would apply to reconciling the values for any other year.

Reconciliation - IESO Persistance Reports to Burman Report "Results from 2012 Total"

	Net Energy Savings (kWh)		
	2013	2014	2015
IESO 2012 Persistence Report ('2012' Tab) - Include 2012 Implementation Year Only	1,133,142	1,127,745	1,063,265
Add IESO 2013 Persiseance Report ('2013' Tab) - Include 2012 Implementation Year Only	92,986	92,750	86,811
Add IESO 2014 Persistence Report ('2014' Tab) - Include 2012 Implementation Year Only	424,026	424,026	424,026
Total IESO Report	**1,650,155**	**1,644,521**	**1,574,102**
Results from 2012 Total (Burman Report)	**1,649,595**	**1,643,941**	**1,573,542**
Difference	**(560)**	**(580)**	**(560)**

Along with this response we have submitted a revised interrogatory response to 9-Staff-88, which reflects a correction in the amount of carrying charges applied. Updated rate rider calculations for the LRAMVA amount have been provided in this response.

9-Staff-88

Ref. E9/T6/S1 & Ontario Energy Board *Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017 Rate Applications Chapter 2,* July 14, 2016, pp.42-43.

Please provide a completed LRAMVA workform as discussed in the July 2016 filing requirements at the second reference above.

RESPONSE:

CNPI has attached the LRAMVA workform as part of this interrogatory response. The OEB's LRAMVA workform was designed for LDC's who have one volumetric rate per customer class. CNPI had two different volumetric rates per customer class up to 2016, at which point the rates were fully harmonized. CNPI has attempted to complete the LRAMVA workform using a simple average of the two rates. In addition, the persistence in the workform is calculated based on a ratio of the total sum of each year rather than the actual reported figures from the IESO. As a result, the LRAMVA figure produced by Burman Energy CGI should be a more accurate representation of the LRAMVA value. CNPI has updated the LRAMVA rate rider calculation based on the report prepared by Burman Energy and is claiming carrying costs of $7,711.44 associated with the LRAMVA calculation of $381,209.56.

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in years) | 1 |

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Account 1568	Rate Rider for Account 1568	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	201,294,289	$ 129,116	**0.0006**	***$/kWh***
GENERAL SERVICE LESS THAN 50 KW S	kWh	69,390,323	$ 156,886	**0.0023**	***$/kWh***
GENERAL SERVICE 50 TO 4,999 KW SER	kW	610,067	$ 102,920	**0.1687**	**$/kW**

UNDERTAKING NO. JTC1.12: TO FILE A UPDATED VERSION JUST WITH BRIEF EXPLANATIONS OF THE CHANGES IN EACH OF THE CLASSES

Response:

CNPI's IRR response inadvertently indicated the 2013 R/C ratios from the Cost Allocation model, prior to adjustment with consideration of the Board's Policy Range. Updated values have been provided in the table below. The Settlement Agreement in CNPI's 2013 Application also provided for target R/C ratios in each year 2013-2016, in order to allow harmonization of distribution rates between its service territories during this timeframe. 2016 target ratios have been added to the table to show starting and ending target R/C ratios for the 2013-2016 period.

Current Status of Revenue to Cost Ratios					
	2013 Approved (Settlement)		Status Quo	Proposed	Policy
Class	2013 Target	2016 Target	Ratios	Ratios	Range
	%	%	%	%	%
Residential	91.17	91.50	94.62	95.37	85 - 115
GS < 50 kW	109.34	109.34	109.22	109.22	80 - 120
GS 50 to 4,999 kW	119.68	119.68	106.96	106.96	80 - 120
Street Lighting	96.06	96.06	162.22	120.00	80 - 120
Sentinel Lighting	91.17	91.50	105.08	105.08	80 - 120
Unmetered Scattered Load (USL)	225.82	120.00	72.95	95.37	80 - 120
Embedded Distributor			84.57	95.37	

Explanations of Changes by Class

The slight increase in the Residential R/C ratio is due the percentage of residential distribution revenue to total distribution revenue increasing from 57% in 2013 to 60% in 2017, due to gradual increases in the number of Residential customers.

GS<50 ratios are relatively unchanged.

GS>50 ratios decrease from 2013 to 2017 due to loss of customers and load in that class. The percentage of GS>50 class distribution revenue to total distribution revenue has decreased from 26% to 24% over the 2013 to 2017 period.

Changes to the Street Lighting R/C ratio are the result of revised Board policy on cost allocation with respect to the Street Lighting Class.

The increase in the Sentinel R/C ratio is due to relatively flat class revenue as a result of decreasing customers/connections, coupled with an increase in costs allocated to the Sentinel class in the 2017 cost allocation model as a result of increasing overall revenue requirement.

The change in USL R/C ratios is due to a formula issue in the 2013 cost allocation model that calculated a higher class revenue for USL than CNPI's actual USL class revenue. This error was corrected in the 2017 model.

Note that the above explanations are in the context to the changes from 2013 Approved R/C ratios to Status Quo R/C Ratios. Changes between Status Quote and Proposed ratios are a result of bringing all classes in line with the Board's policy ranges.