Welland Hydro-Electric System Corp.

EB-2016-0110

Application to the Ontario Energy Board

2017 Electricity Distribution Rates

Interrogatory Responses

March 20, 2017

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Exhibit 1 – Administration

Board Staff – Exhibit 1

1-Staff-1
Customer Engagement
Ref: Chapter 2 of the Filing Requirements, Section 2.1.6

Chapter 2 of the Filing Requirements states, "The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations." (Emphasis added)

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement.

Response:

Welland Hydro-Electric System Corp. (WHESC) commissioned, Innovative Research Group Inc. (INNOVATIVE), to help WHESC design information booklets, collect feedback and document its customer engagement process specific to the 2017 Cost of Service (COS) rate application.

The enhanced engagement process included the development of a customer workbook that provided details about the consultation process, electricity 101 (how the Ontario electricity system works), Welland Hydro's system today, pressures on the system and the bill impact of the plan for the various customer groups. The expertise of INNOVATIVE enhanced the customer engagement process with the customer workbook to ensure low-volume customer classes had an opportunity to make informed decisions.

The consultant recorded the consultation sessions and reviewed the contents of the booklet over a 2 hour period which explained detailed costs, updated status and reliability history of the electricity system, which was not detailed in previous customer engagement activities.

The telephone survey of residential and commercial customers was similar to previous surveys, but with more background information about the industry and rate application, to allow for more informed decisions.

The enhanced process included two consultation groups (residential and GS<50 kW) that were paid incentives to attend the session. Timing of the sessions allowed the General Service customers to attend right after the work day 5:30-7:30pm and residential customers to attend from 8-10pm.

The greater than 50kW Large Customer Validation interviews were new to the process. These customers had information meetings with utility staff regarding the rate application based on their individual consumption, and the reliability of the system for their location was reviewed as well. Follow up interviews by a neutral third party (INNOVATIVE) were completed to provide informed feedback on the proposed plan and consultation process.

The commissioning of INNOVATIVE provided an experienced third party consultant to provide customers in all classes an informed customer engagement process specific to the WHESC 2017 Rate Application.

In non-cost of service applications Welland Hydro's customer consultation consists of bi-annual customer surveys, corporate calls conducted in co-ordinations of the City of Welland, meetings with industrials customers, and the occasional "town hall" meeting. The above examples of customer engagement are more related to customer satisfaction customer feedback on services provided as opposed to discussions relating to bill impacts from a rate application.

1-Staff-2
Ref: Responses to Letters of Comment

Following publication of the Notice of Application, the OEB received one letter of comment. Section 2.1.6 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters, they may be accessed from the public record for this proceeding.

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

Response:

(1) Letter of Comment Tracey

Welland Hydro-Electric System Corp. (WHESC) appreciates the comments provided by Tracey.

As shown in the application and evidence, WHESC has actively engaged with its customers, and is aware of challenges faced by customers on fixed incomes such as seniors, customers on disability or social assistance. WHESC is working to address the issue of bill affordability in the following ways:

- Daily interaction with customers in the office, on the telephone and online with well-trained Customers Service to educate and assist customers on energy usage, potential energy savings and energy costs.
- Partnering with the Hope Centre to provide the Ontario Electricity Support Program for on-going, in-bill financial support for qualifying customers.
- Provision of Conservation and Demand Management Programs to assist any interested customers to lower their consumption and manage their bills.
- Providing emergency financial assistance through the Hope Centre through the Low-Income Energy Assistance Program (LEAP).
- Partnering with the Hope Centre to provide support for the Niagara Energy Emergency Fund (NEEF).
- Specific to this Application, WHESC has taken the customer bill impact into consideration for all customer classes. WHESC has balanced the investment required to operate and maintain the distribution system with the cost impact of these investments to all customer classes.

WHESC will continue to work with our customers to help all customers manage the costs of their electricity bills

(2) Letter of Comment Albert Wilson

Welland Hydro-Electric System Corp. appreciates the letter of comment written by Mr. Wilson.

As shown in the application and evidence, WHESC has actively engaged with its customers, and is aware of challenges faced by customers frustrated with increased costs and wages not keeping up with the increase in all customer costs. WHESC is working to address the issue of bill affordability in the following ways:

- Daily interaction with customers in the office, on the telephone and online with well-trained Customers Service to educate and assist customers on energy usage, potential energy savings and energy costs.
- WHESC has developed a Conservation Booklet that customers provide energy saving tips for all types of utilities including electricity, water and gas
- Partnering with the Hope Centre to provide the Ontario Electricity Support Program for on-going, in-bill financial support for qualifying customers.
- Provision of Conservation and Demand Management Programs to assist any interested customers to lower their consumption and manage their bills.
- Providing emergency financial assistance through the Hope Centre through the Low-Income Energy Assistance Program (LEAP).
- Partnering with the Hope Centre to provide support for the Niagara Energy Emergency Fund (NEEF).
- Specific to this Application, WHESC has taken the customer bill impact into consideration for all customer classes. WHESC has balanced the investment required to operate and maintain the distribution system with the cost impact of these investments to all customer classes.

WHESC will continue to work with customers on programs and education to assist customers with managing the impact of their electricity bills.

1-Staff-3
Customer Consultation
Ref: Ex.1/Section 2.1.6

Welland Hydro commissioned INNOVATIVE to help design, collect feedback and document its consultation processes as part of the developments of its 2017 cost of service application. Welland Hydro notes that the summary provided by INNOVATIVE includes feedback from 16 customers who participated in the qualitative stage of the consultation. In addition, feedback from another 501 residential customers and 25 low- volume general services (GS<50 kW) who responded to the quantitative stage where INNOVATIVE documented the incidence of *needs* and *preferences* across the customer population.

a) **Does Welland Hydro find the response rates acceptable as a basis for measuring customer satisfaction? If so, why?**

<u>**Response:**</u>

Yes, Welland Hydro considers the response rates acceptable as a basis for measuring customer satisfaction.

The qualitative focus group phase of the customer consultation was designed to help inform the quantitative phase (i.e. the telephone surveys). Margins of error <u>cannot</u> be applied to qualitative research.

INNOVATIVE conducted two customer surveys by telephone for Welland Hydro. Respondents were randomly selected from customer lists provided by Welland Hydro (18,216 residential records and 958 general service records).

a) A residential customer survey conducted among **501 respondents** between August 5th and August 11th, 2016. A sample of 501 residential customers is considered accurate to within ±4.3 percentage points, 19 times out of 20.

b) A general service customer survey conducted among **25 respondents** between August 8th and August 17th, 2016. A sample of 25 general service customers is considered accurate to within ±19.4 percentage points, 19 times out of 20 (*due to the size of the margin of error on general service customers, these results should be interpreted as directional only*).

The margin of error in both surveys will be larger within each sub-grouping of the samples.

Note on low response rate for GS under 50 kW: The sample for the general service survey was drawn from a list of **958** which was provided to INNOVATIVE by Welland Hydro. General Service respondents were screened to ensure they were in charge of managing the electricity bill at their organization.

While best attempts were made to survey as large a group of general service customers, given the limited available number of customers in this rate class, INNOVATIVE was only able to survey 25 general service customers.

Before retiring any randomly selected telephone number from the contact list, 8 attempts were made to reach a potential respondent for each unique telephone number, or until an interviewer received a hard refusal. Each day a new sample was released from the contact list to replace completed or retired numbers.

b) How much weight did Welland Hydro give to the identified customer preferences in setting priorities for investment?

Response:

Responses to the residential customer survey helped set priorities for WHESC investment. Feedback from other phases of the customer consultation was deemed directional and did not garner the same weight as the residential telephone survey.

WHESC ensured the responses from customer engagement were incorporated into setting priorities for the distribution plan.

c) What steps does Welland Hydro intend to undertake to improve customer views of Welland Hydro's performance. In your response, please address actions taken for commercial customers as well as other customers.

Response:

- Improve communication on Twitter to include outage information for residential and commercial customers
- Develop an outage management application to be available for all customers
- Plan and advertise events with low income agencies to help our vulnerable customers such as OESP days
- Meeting with large customers as follow up to the rate application and the ICI IESO program
- Maintain an open office for customers staffed with a well-trained Customer Service Team
- Addition of email address for quick customer response csr@wellandhydro.com

1-Staff-4
Customer Consultations
Ref: Ex.1/Section 2.1.6, Pages 64-65

At the above reference, Welland Hydro notes that with respect to one project relating to customer service options with a total cost of $40,000, less than half of survey respondents felt that this should be implemented in 2017 with the majority saying it would be "nice to have" versus "need to have". In addition, in a 2016 customer survey, 70% of customers surveyed indicated they are not willing to pay for services for specific items related to "increased self-service options on the website."

Welland Hydro opted to leave this project in the 2017 test year noting that given ongoing changes some flexibility is required to finance these changes. However, Welland Hydro has noted its customer's feedback and will consider its investments diligently within this area of capital spending.

a) **Has Welland Hydro adjusted its planned spending within this area of capital spending for the forecast period taking into account the feedback provided by its customers? If so, what adjustments were made?**

Response:

Welland Hydro's capital spending related to online self-service options included $40,000 in each of the 2016 Bridge Year and 2017 Test Year. Based on customer feedback Welland Hydro can confirm that it did not spend any capital funds on this project in the 2016 Bridge Year and has removed this item from the 2017 Test Year.

b) **Was this project the sole discrete project mentioned to customers in Welland Hydro's customer engagement process regarding its DSP?**

Response:

Yes

c) **If the answer to (b) is yes, please explain why. If the answer to (b) is no, please provide further examples of discrete projects Welland Hydro sought out specific feedback.**

Response:

The majority of capital spending in the 2016 Bridge Year and 2017 Test Year were System renewal related. It would be difficult for customers to choose between specific underground and overhead projects. Welland Hydro was seeking customer feedback on the level of capital spending over the 2017-2021 forecast period and the impact on 2017 distribution rates.

It would be difficult to impossible to take customers through a detailed review of every single project in the DSP, many of which are technically complicated. Customer engagement needs to be conducted with a deference to and respect of our customer's time limitations as well. As a consequence, Welland Hydro focused seeking customer input on a key project where customer preference could provide a valuable input into Welland Hydro's decision process.

1-Staff-5
Ref: Ex.1, Page 22
Ref: Ex. 4, Page 12

At the above references Welland Hydro discusses its focus on succession planning since its 2013 cost of service application.

If available, please file Welland Hydro's succession plan and/or related documents.

Response:

Welland Hydro does not have a stand-alone succession plan document, however details of Welland Hydro's succession plan are already stipulated in Exhibit 4.

A summary of the key steps related to succession planning include the following:

2012-Administrative Assistant in Engineering replaced by Engineering Technician to provide succession planning and fully implement GIS system.

2013-Apprentice Lineman hired (added position) to supplement aging workforce.

2015-Senior Accountant (CPA) replaced Accounting Assistant to provide succession options in finance department.

2017-Senior Engineer replaces a vehicle mechanic position to provide succession options in Operations & Engineering. No increase in total FTEs.

As noted in Exhibit 4, Welland Hydro reviews its workforce on an ongoing basis to evaluate future retirements including internal replacement options with a goal of maintaining current FTEs.

1-Staff-6
Ref: Ex.1, Page 38, Table 1-3 Service Revenue Requirement

OEB staff notes that the table referenced above shows proposed OM&A for the 2017 test year of $6,987,007. OEB staff notes that the proposed OM&A noted in other sections of the application show a total amount of $6,999,907.

Please confirm if the number listed in Table 1-3 was in error. If not, please explain the discrepancy.

Response:

Table 1-3 showed OM&A net of LEAP payments for presentation purposes only. OM&A of $6,897,007 and LEAP of $12,900 shown in Table 1-3 total $6,909,907 which is noted in other sections of the application.

1-Staff-7
Customer Consultation – 2017 Rate Application Review
Ref: Ex.1, Page 57

Welland Hydro notes that incentives were provided to those customers who participated in the General Service and Residential consultation groups as recognition of their time commitment.

Please describe the incentives that were offered to customers for participating in the consultation groups.

Response:

General Service <50 kW	$100.00 per participant
Residential Customers	$80.00 per participant

1-Staff-8
Ref: Ex.1, Page 61

At the above reference, Welland Hydro discusses overall take-aways from key account customers interviewed by INNOVATIVE with respect to the consultation process and the job Welland Hydro has done in communicating its proposed Distribution System Plan. While most key account customers understood the need for a rate increase and support the plan, one industrial customer expressed concern and opposed the increase.

Please identify if any follow-up occurred between Welland Hydro and this industrial customer to address the concern(s).

<u>Response:</u>

WHESC has followed up with the industrial customer to address concerns. Welland Hydro worked closely with this customer in evaluating the Class A program when the kW threshold was lowered and they became eligible. The customer opted into the Class A classification in the ICI program and has realized significant savings each month since July 1, 2016. The WHESC Conservation Team is currently working with this customer on a conservation program of targeting and monitoring usage and demand and has made numerous visits to the manufacturing facility.

1-Staff-9
Customer Engagement Session – Town Hall Meeting August 25, 2015
Ref: Ex.1, Pages 65-66

Welland Hydro held a customer engagement session (town hall meeting) in August 2015 where 150 customers were contacted, and 13 actually attended. Numerous items were discussed including payment preferences, bill presentment etc.

a) Please explain the criteria used to select the 150 customers contacted or was this done at random.

Response:

Customers were selected at random.

b) Has Welland Hydro adjusted its planned spending for the forecast period taking into account the feedback provided by its customers?

Response:

Welland Hydro did not adjust 2017 OM&A expenses as a result of feedback received by its customers. However, Welland Hydro did adjust its capital spending related to remove the on-line customer service options based upon customer feedback.

c) Does Welland Hydro find the attendance rates acceptable as a basis for measuring customer wants? If so, why?

Response:

Yes, WHESC considers the attendance rates acceptable as a basis for measuring customer wants in the context of a qualitative research exercise.

Qualitative research is designed to help inform the design of subsequent quantitative research. The feedback and findings from this exercise are interpreted as directional only.

d) How much weight did Welland Hydro give to the identified customer preferences in setting priorities for investment?

Response:

Because of the small sample size, Welland Hydro interpreted the data as directional only. Although the customer size is relatively small, WHESC was able to provide individual attention to customer issues and explain in detail some of the online services such as e-billing that some customers had questions about. Also, by spending time with each customer individually, we were able to answer concerns that customers may not have felt comfortable asking in a large group session. One customer requested a site visit after the session to look at an old service coming into his older home, which was completed the following day. The Focus Group session was a qualitative session used to help understand the direction of customer preferences.

1-Staff-10
Customer Satisfaction Survey Results

Ref: Ex. 1, Page 71

At the above reference, Welland Hydro discusses certain topics included in its 2015 customer satisfaction survey related to operating and capital expenditures. Customers were surveyed on questions relating to: "run to failure" versus "proactively replacing equipment", and their level of confidence in Welland Hydro's judgment on prioritizing and making decisions on these investments. Additional questions relating to customers' willingness to pay more for items such as increased tree trimming, extended office hours, education on conservation and public safety, and outage management systems. Customers were surveyed on how much more per month they would be willing to pay for items that they considered to be a direct benefit to themselves.

a) Please provide a summary of customers' feedback related to specific capital expenditure projects.

Response:

The Tables below summarize the customer feedback from questions asked in the 2015 Customer Service Survey.

Welland Hydro	Yes	No	Not Sure	Don't Know
An Outage Management System	53%	40%	6%	1%
Increased self-service online options	37%	56%	5%	2%
Extended office hours	21%	77%	2%	1%
Increased tree trimming	63%	33%	2%	1%
Better use of social media	31%	66%	2%	2%
Energy Consevation education	57%	41%	1%	1%
Public Safety education	55%	43	1%	1%
Which of the items are you willing to pay more for per month...				

Welland Hydro	1 Item	2 Items	3 or more items
$.25 or less	60%	50%	38%
$0.26 - $0.50	12%	0%	12%
$0.51 - $1.00	18%	21%	17%
$1.01 - $2.00	8%	11%	12%
$2.01 - $3.00	0%	2%	7%
$3.01- $5.00	2%	5%	6%
$5.01 +	0%	4%	7%
Don't Know	0%	7%	0%
Willing to pay how much more per month for...			

b) Were any of these results incorporated into the filing of this cost of service application by increasing certain spending in areas of capital expenditures?

<u>Response:</u>

No increases to capital spending were made as a direct result of the customer engagement process.

1-Staff-11
Ref: Exhibit 1, Page 84
Ref: Exhibit 1, Appendix 1-L, 2015 Reconciliation to Financial Statements

On page 84, it states that the IFRS Adjustment column items are related to financial presentation and are offsetting. In the 2015 reconciliation to the financial statements, there is a net adjustment to PP&E of $232k and intangibles of $368k.

a) **Please explain what the net adjustments to PP&E and intangibles are for. Please also explain how the net adjustment of $232k and $368k to PP&E and intangibles are offsetting.**

Response:

The net adjustments of $232K and $368K do not offset each other and are part of a larger entry related to PP&E which do offset as follows:

Account 1330 Inventory	($100,000)
Property Plant & Equipment Net	$231,981
Intangible Assets Net	$368,106
Deferred Revenue IFRS	($500,085)
Net Entry	$NIL

There are three different adjustments made to PP&E and Intangible Assets between the OEB and IFRS.

1. Capital Spares in inventory for IFRS (same under CGAAP) is not made for OEB reporting purposes. A reduction in Inventory of $100,000 and an increase of PP&E of $100,000 is made under financial reporting. Capital Spares included in PP&E for financial reporting are not depreciated.

2. Effective with the implementation of IFRS on January 1, 2014 Accumulated Depreciation was netted against historical Gross PP&E which provided a new Gross PP&E for financial reporting purposes going forward. There was no change to the net PP&E amount. However, OEB requirements prohibit the netting of Accumulated Depreciation against Gross PP&E Assets. As a result, Welland Hydro must maintain separate fixed assets ledgers in order to meet OEB reporting requirements.

3. Contributed Capital included in PP&E for OEB reporting is recorded as a liability under IFRS for financial statement reporting purposes.

b) **Please explain why intangible assets under the IFRS column are reclassified so that it is $0 under OEB Year Book column.**

Response:

Welland Hydro has not been able to properly reflect Intangible Assets accounts for RRR reporting. These would include accounts 1611 Computer Software and 1612 Land Rights. Welland Hydro was advised by OEB staff that these accounts are not accessible for reporting purposes until a distributor has had a Cost of Service Rate application processed under IFRS. Please note that this has no impact on actual rate base used in the rate application. The recent change in the RRR reporting for 2016 will allow Welland Hydro to access the IFRS accounts used for reporting purposes.

SEC – Exhibit 1

1.0-SEC-1

[Ex. 1, p. 11] Please provide the "extensive assessment" referred to at line 26.

Response:

The extensive assessment took place at numerous senior management and staff meetings to review all aspects of manpower levels and operating expenses on line by line basis.

1.0-SEC-2

[Ex. 1, p. 14] Attached are two tables comparing the 2016 and 2017 typical distribution bills for all of the electricity distributors in Ontario, based on Board orders, draft rate orders, and rate applications, as indicated. With respect to the existing and proposed distribution bills for the Applicant:

a) Please confirm that, to the best of the Applicant's knowledge, the calculations in the attached tables are correct. If the Applicant believes any are incorrect, please provide details.

Response:

Calculations appear to be correct without performing an extensive review.

b) Please confirm that the Applicant is proposing to move from the 18th highest rates in the province to the 34th highest rates in the province. Please explain how this maintains rates that are "competitive with LDCs in Ontario".

Response:

Based on the methodology of the spreadsheet Welland moves to 34th highest in the province. At 98.19% this is still below the average rate for the province of Ontario assuming 100% is the average. However, this benchmarking assumes a Residential volume of 800 kWh per month. Welland's Residential rates are based on 626 kWh per month which results in significantly less distribution revenue than the $348 included in the analysis. Welland believes that this model is helpful in that it recognizes the three main classes of rates. Welland used its analysis in Exhibit 1 based on distribution revenue per customer which takes out volume effects from the analysis which will be the case in 2019 when Residential Rates are fixed per month.

c) Please confirm that the Applicant currently has the 33rd highest residential distribution bills in the province, and proposes to move to 43rd highest (out of 63) in 2017. Please explain how this maintains residential rates that are "competitive with LDCs in Ontario".

Response:

See response to (b) above. To perform a complete analysis the volumes on which residential rates are set needs to be taken into consideration. In the analysis presented, Welland would be at 100.7% compared to the average LDC in 2017 without taking volumes into account.

d) Please confirm that the Applicant current has the 27th highest GS>50 distribution bills in the province, and proposes to move to 41st highest in 2017. Please explain how this maintains GS>50 rates that are "competitive with LDCs in Ontario".

Response:

Based on the analysis presented Welland Hydro moves to 41st highest for GS>50 at 104.7% compared to the average LDC in the province. When the analysis is expanded to cover total General Service Customers (both above and below 50kW) Welland Hydro would be at 96.95% (below average) compared to the average for LDCs in 2017.

e) Please confirm that the Applicant believes the six Niagara area LDCs are the appropriate comparator group for the Applicant's rates.

Response:

Rate comparisons are just one tool used to evaluate Welland Hydro's performance and efficiency as an LDC. Comparisons are made to local LDCs and average LDCs across the province of Ontario. But rates are not the only tool to be used as there are differences between LDCs such as size of territory and customer base. Results of efficiencies derived from the PEG model should also be taken into consideration.

f) Please confirm that the Applicant's residential rates are currently lower than all Niagara area LDCs, but that under the current proposals in 2017 it will move higher than Grimsby and Horizon, but remain lower than the other three comparators. Please explain the main factors causing Welland Hydro to have greater cost pressures for residential customers than Grimsby and Horizon.

Response:

As stated in response to (b) the analysis does not take into consideration volumes on which residential rates are based. Information obtained from the 2015 annual report shows the average residential customer in Welland consumed 635 kWh/month versus 756 kWh/month for Grimsby. Welland believes that the distribution revenue collected from customers would be similar to Grimsby when total revenue per customer is used as the comparison as opposed to 800 kWh used in the analysis. Despite a significantly higher customer base than Welland, Horizon's total distribution rates for all three classes used in the analysis is higher than Welland Hydro.

g) Please confirm that the Applicant's GS>50 rates are currently lower than all Niagara area LDCs except Niagara-on-the-Lake, but that under the current proposals in 2017 only Canadian Niagara Power would be higher than the Applicant. The other four would be lower. Please explain the main factors causing Welland Hydro to have greater cost pressures for GS>50 customers than the other Niagara area LDCs.

Response:

It is difficult to analyze the cost pressures at Welland compared to other LDCs in Niagara without extensive analysis. However, from the data provided in the analysis Welland's overall GS (above and below 50 kW) is favorable compared to both Niagara and Ontario LDCs.

1.0-SEC-3

[Ex.1, p. 17] Please explain why the Applicant has set 2017 targets for SAIDI and SAIFI that are worse performance than 2015 actual results.

<u>Response:</u>

Welland Hydro's 2015 OEB Targets for SAIDI of <2.27 and for SAIFI of <1.80 are based on a rolling average. For the Rate Application, Welland Hydro used the lower of the 2015 OEB Target or its 2017 Business Plan. This resulted in the target for SAIDI being set at <2.00 as per the business plan.

Welland Hydro's actual SAIDI and SAIFI for 2016 are provided in 1-VEEC-4 and are both well below 2015 results. Welland Hydro continues to monitor the OEB's introduction for removal of major events for reliability indices and will adjust targets accordingly.

1.0-SEC-4

[Ex.1, p. 40] Please confirm that the reduction of the working capital percentage from 12% to 7.5% reduces rate base by $2.4 million, and reduces revenue requirement by more than $180,000. Please show where that driver of the deficiency is included in the summary on page 40.

<u>Response:</u>

The reduction in the Working Capital Allowance percentage from 12% to 7.5% reduces the rate base by $2.4 million. The original RRWF contained a Return on Rate Base of 6.28%. This reduces the return on rate base by $151,401. To get to the $180,000 Welland Hydro assumes SEC is adjusting this amount by PILS associated with the $151,401.

The summary on page 40 is taken from Table 6-5 on page 9 of Exhibit 6. Table 6-5 compares 2017 Revenue at existing rates in proportion to 2013 Revenue Requirement components and compares those calculations to 2017 Proposed Revenue Requirement. The difference in the Return on Rate Base is $217,159 as can be seen in Table 6-5. Please note that this table separates the impact of PILS from Return on Rate Base.

Below is a Revision to the bottom half of Table 6-5 which separates the Return on Rate Base from increases related to Average Fixed Assets and Working Capital Allowance and the increase in Rate of Return from 5.77% to 6.28%.

	2013 Approved (A)	2017 Revenue at Existing Rates Allocated in Proportion to 2013 Approved (B)	2017 Proposed (C)	Difference (C - A)	Rate of Return at 5.77%	Change in Rate of Return to 6.28%	Total Change in Return on Rate Base
Rate Base Average Fixed Assets	25,464,079	26,517,731	29,494,306	2,976,575	171,748	151,896	323,644
Rate Base Working Capital Allowance	5,971,788	6,218,889	4,018,082	-2,200,807	-126,987	20,492	-106,494
Rate Base	31,435,867	32,736,620	33,512,388	775,768			
Return on Rate Base	5.77%	5.77%	6.28%		44,762	172,388	217,150

Please note that the impacts of the 2017 Cost of Capital returns has reduced the Return on Rate Base to 5.67% which has been used in responses to interrogatories.

1.0-SEC-5

[Ex. 1, p. 59] Please confirm that 81% (31% + 50%) of customers believe that capital should be invested at levels less than or equal to the levels necessary to maintain current outage levels, but not at levels needed to improve outage levels.

<u>Response:</u>

Assuming 19% of customers think capital spending should be made to reduce current outages, by default 81% think capital spending levels should maintain current outages.

1.0-SEC-6

[Ex.1, p. 60] Please provide a list of asset classes/types that the Applicant will continue to run to failure notwithstanding the views of residential customers as expressed in the survey.

<u>Response:</u>

There are no asset classes that Welland Hydro intentionally plans to run to failure. All assets are planned to be replaced close to end of useful life. However, failures may occur for asset classes/types including distribution transformers, insulators, arrestors, switches and associated hardware, underground primary and secondary cable, capital tools, and computer hardware. Software may require replacement when vendors no longer provide support and maintenance.

Higher risk assets receive additional inspection and testing to reduce the risk of failure prior to planned replacement. Public and employee safety is also factored into replacement decisions.

1.0-SEC-7

[Ex. 1, p. 65] Please confirm that the Applicant only asked for feedback from customers on one General Plant project, and for that project 70% of the customers said No. Please provide details as to why website self-service options would cost customers more than the costs currently incurred by the Applicant for providing those services.

<u>Response:</u>

Welland Hydro asked customers for feedback about overall capital spending in addition to the specific question about website self-service capital spending. Welland Hydro did not proceed with the software programming budgeted for 2016 and 2017 in response to customer feedback. See response to Board Staff 1-4.

1.0-SEC-8

[Ex. 1, p. 75] Please explain why the benchmarking model filed by the Applicant shows that the Predicted Cost for the Applicant should increase from 2016 to 2017 by 6.47%. Please confirm that, despite the Applicant's costs increasing from 2016 to 2017 by 5.24%, the high increase in Predicted Cost is the only reason why the Applicant's Cost Performance improves.

Response:

WHESC has reviewed the benchmarking model developed by Pacific Economics Group Research LLC (PEG). In WHESC's view the benchmarking model is somewhat of a "black box" and difficult to fully understand. However, through a trial and error process WHESC has determined that it appears the primary driver to determine the predicted costs in the model is the Rate of Return (WACC) assumed in the year. The secondary drivers are Number of Customers and the Ten-Year Customer Growth Percentage. Since Number of Customers directly impacts the Ten-Year Customer Growth Percentage it appears the secondary driver is Number of Customers. This means the main reason for the Predicted Cost to increase from 2016 to 2017 by 6.47% is the increase in Rate of Return (WACC) from 5.91% in 2016 to 6.28% in 2017 along with an increase in Number of Customers from 22,868 in 2016 to 23,080 in 2017.

WHESC confirms that the increase in Predicted Cost is based on the Board's approved benchmarking model, which is used each year to set the stretch factors for all distributors, is the reason why WHESC's Cost Performance improves.

1.0-SEC-9

[Ex 1, p. 75] Attached is a table showing the benchmarking results for all current LDCs for the six years ending 2015, showing the Applicant 12th in Ontario in cost performance, on both a three-year average and one year (2015) basis.

a) Please advise if the Applicant believes any of the figures in the table are incorrect.

Response:

WHESC has reviewed the provided table showing the benchmarking results for all current LDCs for the six years ending 2015 and in particular reviewed the detailed results for the first 12 Distributors including WHESC and found that there are incorrect numbers in 2013 for Northern Ontario Wires and Cooperative Hydro Embrum. WHESC has not reviewed the remaining Distributors.

b) Please confirm that the predicted costs of the Applicant in the model in 2013 were $12,272,513, and that pursuant to the model the predicted costs of the Applicant were expected to increase by 18.90% from 2013 to 2017, a compound annual growth rate of more than 4.4% per year.

Response:

Confirmed.

c) Please confirm that the actual costs of the Applicant in the model in 2013 were $10,542,875, and that it is forecast that they will increase to $11,960,287 in 2017, an increase of 13.44%, which is a CAGR of 3.2% per year.

Response:

Confirmed.

d) Please explain why, given the declining volumes being delivered to customers by Welland Hydro over that same period, it is appropriate for actual costs to increase at more than inflation.

Response:

Welland Hydro believes that its application reflects OM&A costs to provide service in:

1. A public policy environment where obligations are constantly being downloaded on LDCs (including customer engagement, increased OEB assessment fees, implementing the 25% fair hydro plan discount, etc.);

2. A utility with aging employees and succession planning needs all of which create cost pressures well in excess of inflation.

1.0-SEC-10

[App. 1-I, p. 32] Please explain how the 6.25% promissory note can be described as having "no material difference between market and carrying values".

<u>Response:</u>

The above terminology was written when the accounting for financial instruments was first introduced. From a technical accounting point of view, Welland Hydro should on an annual basis obtain a market value and book entries to reflect the difference between market and carrying values. However, this adjustment may or may not provide value to the readers of the financial statements assuming you could determine market value which would require additional consulting costs on an annual basis.

1.0-SEC-11

Please provide a copy of the most current Shareholder Declaration, if any. If the Shareholder Declaration has changed since the date the EB-2012-0173 application for the last rebasing was filed, please provide the Shareholder Declaration at that time, and all revisions since then.

Response:

A copy of the current Shareholder Declaration and copies of 2013-2016 dividend resolutions are attached in Appendix A.

1.0-SEC-12

Please describe how, if at all, the Applicant's policies or approaches with respect to operational and capital expenses changed due to the results of the customer engagement activities.

<u>Response:</u>

See 1-Staff 4

VECC – Exhibit 1

1.0-VECC-1
Reference: E1/T/pg.65

a) If Welland has concluded from its survey's that customers are not willing to support IT investments for improved on-line services, why then is Welland proceeding with this project?

Response:

See Response to Board Staff 1-4 and 1.0-SEC-7.

b) Two figures are discussed in the description of the project(s) for on-line improvements - $40,000 in "Total Cost of the Project" and $50,000 or less in upgrades to computer systems. Please clarify the total cost of the project and what portion(s) of the amounts are expected to be spent during the rate plan period.

Response:

The total cost of the customer online forms project was $80,000 which included $40,000 in each of the 2016 Bridge Year and 2017 Test Year. As per response to Board Staff 1-4 no monies were expended in 2016 and this project was removed from the 2017 Test Year. The $50,000 per year from 2018-2021 is for unidentified software purchases or upgrades.

1.0-VECC-2
Reference: E1/pgs.74 & 75

a) Please update Table 1-22 to include 2016 actual results.

Response:

System Reliability Measures	2011	2012	2013	2014	2015	2016	2015 OEB Target WHESC	Performance Improvement Targets
The Average Number of Hours that Power to a Customer is interrupted (SAIDI)	2.84	1.26	4.86	1.53	1.74	0.61	2.27	1.53
The Average Number of Times that Power to a Customer is interrupted (SAIFI)	1.92	1.33	2.34	1.76	1.39	0.70	1.80	1.39

b) What are the consequences of failing to meet the performance improvement targets for SAID and SAIFI? Specifically, what impact does failure have on compensation for the Welland management?

Response:

There are no implications to management compensation for failure to meet System Reliability targets nor are there any incentives when System Reliability targets are exceeded.

1.0-VECC-3
Reference: E1/pg. 76, 77, 81

a) Please update Table 1-23, 1-24 and 1-26 for 2016 results.

<u>Response:</u>

Table 1-23 is updated below to include unaudited 2016 Actuals.

Cost Control Measures	2011	2012	2013	2014	2015	2016 Actual (Unaudited)	Performance Improvement Targets
Efficiency Assessment	n/a	2	2	2	2	2	2
Efficiency Performance Current Year	-16.2%	-10.4%	-15.2%	-17.3%	-18.7%	-17.7%	-19.9%
Efficiency Performance 3 Year Avg.	n/a	n/a	-13.9%	-14.3%	-17.0%	-17.9%	-19.1%
Total Cost per Customer	$463	$482	$472	$483	$493	$503	$518
Total Cost per km of line	$33,562	$23,071	$23,533	$23,278	$23,293	$23,937	$24,917

Welland Hydro has provided an updated Table 1-24 from the PEG forecasting model based on 2016 Actuals (Capital, OM&A, Customer Count/Usage but excluding changes to km of line which were forecasted to remain unchanged) and 2017 Revised Test Year information as follows:

Summary of Cost Benchmarking Results

Welland Hydro-Electric System Corp.

	2015 (History)	2016 (Bridge)	2017 (Test Year)
Cost Benchmarking Summary			
Actual Total Cost	11,180,484	11,490,213	11,684,231
Predicted Total Cost	13,473,782	13,715,983	14,135,352
Difference	(2,293,297)	(2,225,770)	(2,451,121)
Percentage Difference (Cost Performance)	**-18.7%**	**-17.7%**	**-19.0%**
Three-Year Average Performance			-18.5%
Stretch Factor Cohort			
Annual Result	2	2	2
Three Year Average			2

A revised Table 1-26 to include 2016 Actuals (unaudited) is as follows:

Financial Ratio Measures	2011	2012	2013	2014	2015	2016	Performance Improvement Targets
Liquidity: Current Ratio (current assets/current liabilities)	2.87	2.84	1.42	1.61	1.50	1.46	>1.0
Leverage: Total Debt to Equity Ratio	1.23	1.16	1.15	0.87	0.84	0.82	<1.5
Profitability: Regulatory Deemed	8.01%	8.01%	8.93%	8.93%	8.93%	8.93%	9.14%
Profitability: Achieved	5.74%	6.73%	10.50%	9.98%	8.72%	6.48%	9.14%

1.0-VECC-4
Reference: E1/ PDF pg. 144

a) Please update the Scorecard to include 2016 actual results.

Response:

See Unaudited 2016 Scorecard Results as follows:

Scorecard-Welland Hydro-Electric System Corp.

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	2016	Comments
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	94.00%	100.00%	100.00%	Actual
		Scheduled Appointments Met On Time		99.70%	99.70%	99.40%	99.70%	98.50%	98.50%	Actual
		Telephone Calls Answered On Time		99.90%	98.40%	99.00%	96.90%	98.50%	98.60%	Actual
	Customer Satisfaction	First Contact Resolution					78%	84	84	Actual
		Billing Accuracy					99.99%	99.99%	99.99%	Actual
		Customer Satisfaction Survey Results					88%	90	92	Actual
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives	Safety	Level of Public Awareness						84.00%	84.00%	Actual
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C	Actual
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	1	Actual
			Rate per 10, 100, 1000km of line	0.000	0.000	0.000	0.000	0.000	0.208	Actual
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		2.84	1.26	4.86	1.53	1.74	0.61	Actual
		Average Number of Hours that Power to a Customer is Interrupted		1.92	1.33	2.34	1.76	1.39	0.70	Actual
	Asset Management	Distribution System Plan Implentation Progress					On Track	On Track	Filed	Actual
	Cost Control	Efficiency Assessment			2	2	2	2	2	Peg Model
		Total Cost per Customer		$463	$482	$472	$483	$493	$503	Unaudited no change in km of line
		Total Cost per Km of Line		$33,562	$23,071	$23,533	$23,278	$23,293	$23,937	Unaudited
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings						6.78%	Not Available	CDM Savings Not Available
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time		50.00%						
		New Micro-embedded Generation Facilities Connected on Time				100.00%	100.00%	100.00%	100.00%	Estimated
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ration (Current Assets/Current Liabilities)		2.87	2.84	1.42	1.61	1.5	1.46	Unaudited
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.23	1.16	1.15	0.87	0.84	0.82	Unaudited
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.01%	8.01%	8.93%	8.93%	8.93%	8.93%	Actual
			Achieved	5.74%	6.73%	10.50%	9.98%	8.72%	6.48%	Unaudited

1.0-VECC-5
Reference: E1/ Appendix 1-G Innovative Research Group Study pg.58 (PDF pg.237)

a) **The Innovative Survey indicates that 33% of Welland customers are unaware of e-billing options. What efforts has Welland made to communicate alternatives to paper billing?**

Response:

Welland Hydro is training Customer Service Representatives to review e-billing options with customers when they register for new services and assist with answering questions during the e-billing registration process. Welland Hydro is also preparing an on-hold message outlining the benefits and procedures for e-billing. Welland Hydro is also working with the Hope Centre to communicate to customers setting up OESP, LEAP or NEEF, the benefits of e-billing.

Prior promotions related to e-billing options which included monthly draws (iPad) have not proved successful in prior years.

1.0-VECC-6
Reference: E1/Appendix 1-G/pgs.12 & 18 (PDF pgs. 191 &197)

a) The Innovative Research Group Report states "*However, several* (residential customers) *did object to the deposit that is required to open a Welland Hydro account, even if their account with a previous local distribution company was in good standing*." Please provide the Welland's requirements with respect to customers attempting to demonstrate 1 year of good payment history with another utility (as set out in the Distribution System Code).

<u>Response:</u>

Welland Hydro waives deposits for customers if they are a qualified low income customer. In addition, deposits are waved if new customers can demonstrate one (1) year of good payment history from another utility [received one (1) or less disconnection notice over the past year, one (1) or less NSF cheques in the last year or if the service was not disconnected for non-payment over the last year], if the customer provides a satisfactory customer credit record and more recently a pilot program was initiated for waiving deposits for customers that select the Pre-Authorized Payment option.

1.0-VECC-7
Reference: E1/Appendix 1-G

a) **Were the participants aware of the participation incentive ($100 GS / $80 Residential) prior to taking the survey?**

Response:

Yes, customers were aware of the incentive prior to participating in the focus groups.

b) **Welland has a residential and GS customer population of over 22,000 of which 16 participated in the survey. What is the statistical significance /margin of error for this survey?**

Response:

The qualitative focus group phase of the customer consultation was designed ultimately help inform the quantitative phase (namely the telephone surveys). Margins of error cannot be applied to qualitative research.

c) **Given the survey size why the results should be considered meaningful?**

Response:

See above.

1.0-VECC-8
Reference:

a) Please provide a table showing for the period 2012 through 2016
- **i. Net earnings**
- **ii. Retained earnings beginning of year**
- **iii. Dividends**

Response:

	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Forecast
Retained Earning Start of Year	$260,828	$967,001	$1,369,678	$1,998,186	$3,147,930
Net Income After Tax OEB	$1,106,173	$1,102,677	$1,128,508	$1,219,586	$988,135
Transfer Paid in Capital				$630,158	
Actual Dividend Paid to Holding	$400,000	$700,000	$500,000	$700,000	$700,000
Retained Earnings End of Year	$967,001	$1,369,678	$1,998,186	$3,147,930	$3,436,065

b) Please provide Welland's Dividend policy.

Response:

See Welland Hydro-Electric System Corp. Dividend policy on next page.

BOARD POLICIES AND PROCEDURES

	P 100-02	Page 1 of 1

Department BOARD OF DIRECTORS	**Name of Policy** DIVIDEND POLICY
DATE ISSUED: October 23, 2013	**DATE REVISED**:

Resolution No. 10/23/13-02 Corporate Secretary Signature: ______________________________
Ross Peever

POLICY STATEMENT

Welland Hydro-Electric System Corp. (WHESC) provides a dividend to the Welland Hydro- Electric Holding Corp. (WHEHC) on a yearly basis. In turn WHEHC dividends those funds to the Shareholder (City of Welland) on a yearly basis.

PURPOSE

The purpose of this policy is to establish and make known WHESC expectations, requirements and framework regarding dividend funds made to WHEHC.

GENERAL

1. WHESC shall provide on a yearly basis to WHEHC a dividend fund set at 60% of the yearly planned net income inclusive as the base dividend amount.

2. Based on the year ends net income results, a further dividend payment to the WHEHC will be considered.

3. WHEHC shall recommend to the Shareholder (City of Welland) to consider utilizing the additional dividends, above the base amount, for capital projects or one off projects (projects only occurring once) that are sustainable or clean energy related and will help to reduce operating costs or provide a reasonable revenue stream.

RELATED ADMINISTRATIVE RESOLUTIONS/PROCEDURES/FORMS:

Resolutions/Procedures/Forms	Document #
Supporting Resolution – WHESC	**10/23/13-02**
Supporting Resolution – WHEHC	**10/23/13-02**

ENERGY PROBE – Exhibit 1

1.0-Energy Probe-1

Preamble: WHESC (WH) has filed this COS Application for Rate Year 2017.
Energy Probe would like to understand WH's proposal(s) for setting rates in 2018-2021.

a) Please provide a summary of WH plans for 2018-2021, specifically the form of COS/IRM WH expects to use for setting rates in 2018-2021. Reference the RRFE and Filing Guidelines.

Response:

Welland Hydro currently plans on filing Price Cap IR Rate Applications for each year from 2018 to 2021.

b) If the proposed IRM involves either a Capital Module, or Custom form with Capital forecasts please provide more details in this regard.

Response:

There are currently no plans to include a Capital Module or Custom form with capital forecasts during the 2018 to 2021 IRM rate setting period.

c) Will the Distribution System Plan as filed (once approved) apply to the future rate years or will it be updated?

Response:

The DSP is currently expected to apply to the rate years 2017 to 2021. During the IRM period, Welland Hydro will continue to develop and expand its asset management process including a more detailed asset assessment evaluation process and the development of health indices. It will also reflect any changes required by the regulator at the time of the next Cost of Service Rate Application.

1.0-Energy Probe-2
Reference: Revised Exhibit 1, Page 26

a) Confirm based on the requested 2017 Revenue Requirement, the Bill Impacts for low, average and high consumption Residential customers.

Response:

The 2017 Rate Application (original filing) contains an average Residential consumption of 638 kWh per month.

The revised Bill Impact model submitted on December 21, 2016 to reflect the 2017 Cost of Capital Parameters showed the following bill impacts for Residential customers:

Total Bill Impacts

10% Percentile 308 kWh/month	4.18%
Average – 638 kWh/month	1.35%
OEB Determinant – 750 kWh/month	0.86%

b) How much of the Residential Bill Impact for the above consumption level customers relates to the change in the fixed charge? Please provide a summary table and notes for this change relative to 2016 ($ and Percent)

Response:

	Current Rates	**Proposed Rates**	**With Current Fixed to Variable**
Fixed Distribution Charge	$18.76	$22.92	$20.48
Variable Distribution Charge (750)	7.88	5.70	8.62
Total Distribution Charges	**$26.64**	**$28.62**	**$29.10**
Fixed Distribution Charge	$18.76	$22.92	$20.48
Variable Distribution Charge (638)	6.70	4.85	7.33
Total Distribution Charges	**$25.46**	**$27.77**	**$27.81**
Fixed Distribution Charge	$18.76	$22.92	$20.48
Variable Distribution Charge (308)	3.23	2.34	3.53
Total Distribution Charges	**$21.99**	**$25.26**	**$24.01**

The change in the fixed to variable distribution rates produces a monthly decrease of $.48 (1.6%) for the 750 kWh customer, a decrease of $.04 (0.1%) for the 638 kWh customer, and an increase of $1.25 (5.2%) for the 308 kWh customer.

1.0-Energy Probe-3
References Revised Exhibit 1, Page 46, Table 1-6, Exhibit 2, Page 52

Preamble: WHESC's accounting policy is to include projects in fixed assets when they are placed into service. Capital projects which are not yet completed are included in WIP. Capital projects with a life cycle greater than one year will be carried over from one year to the next in WIP.

a) Please provide a Continuity Table Based in Exhibit 1-6 showing for 2015 and 2016 Capex the In-service additions entering Rate Base in 2017.

Response:

Account 2055 is used to account for CWIP at the end of each year which is not reflected in rate base in any year in Table 1-6.

The following is a summary of CWIP at the end of 2015 and 2016 and the year the CWIP entered into rate base.

2015 CWIP	$153,290	2016 In Service Date
2016 CWIP	$ 69,322	2017 In Service Date

There are no planned amounts for CWIP in 2017.

	In Service Capital 2015	**In Service Capital 2016 Adjusted**	**In Service Capital 2017 Adjusted**
2014 CWIP	$55,000		
2015 Capital Spending	2,182,364		
2015 CWIP	(153,290)	$153,290	
2016 Capital Spending		2,837,176	
2016 CWIP		(69,322)	$69,322
2017 Capital Spending			2,208,896
2017 CWIP			0
Total In Service Capital	**$2,084,074**	**$2,921,146**	**$2,278,218**

b) For 2017 based on in-service date information, show Capex that will come in service and flowing into later years.

Response:

See response to (a) above.

c) Please provide the net in-service additions to Rate Base in 2017 and Total Rate Base. Adjust the Return on Capital component of the 2017 Revenue Requirement.

Response:

The net in service additions to Rate Base forecasted for 2017 (revised) are $2,278,218 as can be seen in response to (a) above and 2-Staff-14. The revised Rate Base for 2017 is $33,592,421. The Return on Capital based on the Revised Rate Base is $1,903,212.

1.0-Energy Probe-4
References: Revised Exhibit 1, Page 59 and Page 74, Table 1-22

Preamble: Many customers didn't experience any outages (36%) in the last 12 months. The rest were most likely to experience either one (19%) or two (15%) recent outages. Of those impacted, most experienced an outage of one hour or less with 29% who recall it as less than 15 minutes.

a) Please Update Table 1-22 to include 2016 System Reliability Indicators.

Response:

System Reliability Measures	2011	2012	2013	2014	2015	2016	2015 OEB Target WHESC	Performance Improvement Targets
The Average Number of Hours that Power to a Customer is interrupted (SAIDI)	2.84	1.26	4.86	1.53	1.74	0.61	2.27	1.53
The Average Number of Times that Power to a Customer is interrupted (SAIFI)	1.92	1.33	2.34	1.76	1.39	0.70	1.80	1.39

b) Does WH track other Reliability Indicators, for example MAIFI and Worst Performing Circuits? If so, please provide historic Data and Targets for 2017-2021 for these.

Response:

Welland Hydro currently collects MAIFI data but does not set targets for MAIFI. Below are the MAIFI indexes from 2013-2016 excluding loss of supply.

2013	3.25
2014	3.07
2015	4.16
2016	4.72

c) Does WH track Outage Cause Codes? If so, please provide historic data.

Response:

See figures 5-14 through 5-17 of the Distribution System plan.

d) Please provide for 2013-2016, details regarding how many WH outages (SAIDI/SAIFI) were related to Transmission/Hydro One and how many//duration were WH Distribution Outages.

Response:

	2013	2014	2015	2016
SAIDI – WH	4.86	1.53	1.74	0.61
SAIDI including HONI	4.99	1.53	1.95	0.80
SAIFI – WH	2.34	1.76	1.39	0.70
SAIFI including HONI	3.60	1.76	1.68	1.23
Interruptions WH	265	252	193	256
Interruptions HONI	5	0	1	3

1.0-Energy Probe-5
References: Revised Exhibit 1Page 59; Appendix 1-G Innovative Survey Report

Preamble: Survey respondents were informed of Welland Hydro's proposed capital investment required to maintain system reliability and then asked to think about reliability in terms of bill impact. Almost 7 out of every 10 (69%) of residential customers and 80% of general service customers feel Welland Hydro should spend what is needed to maintain system reliability from the telephone survey.

a) Confirm SAIDI and SAIFI are lagging System Reliability (SR) indicators.

Response:

Confirmed System Reliability indicators are calculated post system interruptions.

b) Has WH determined/modelled the link between Capital Investment in 2017-21 and changes in Reliability Indicators (SAIDI and SAIFI)? If so, please provide complete details.

Response:

Welland Hydro has not modelled the link between 2017-21 capital expenditures and the Reliability Indicators.

c) What specific value proposition(s) was/were put to customers regarding the WH System Reliability Indicator Baseline and Investment levels to increase SR, maintain SR and allow SR to decline to Industry averages? Be specific to each group of ratepayers/respondents.

Response:

Customers were not presented with any indicator baselines or investment levels to increase SR. They were asked questions as to how they feel about historic outage lengths and frequency.

d) What guarantees did/will WH give customers regarding its SR Targets for SR in 2017-2011 and what penalties/rewards will be provided for WH and its Senior Management?

Response:

Welland Hydro does not provide guarantees to customers concerning SR targets. Senior management are not rewarded or penalized based on SR Targets. Should actual SR performance decline below acceptable performance, Welland Hydro's senior management would be required by its Board of Directors to develop an action plan to correct the performance including a review of the current DSP for any changes required.

e) Please explain how Major Events will be addressed in relation to Targets and Rewards/Penalties.

<u>Response:</u>

Welland Hydro is waiting for further details from the OEB in relation to Major Events and how they might impact the setting of SR Targets.

f) Please explain why is the Proposed Investment plan appropriate? Did WH perform Sensitivity Analyses? If so, please provide these.

<u>Response:</u>

The proposed investment plan is considered prudent and reasonable to maintain current Distribution System performance based on historical spending patterns and system performance. No Sensitivity Analysis was undertaken.

g) Please provide a profile of WH major assets by major category and indicate for each how WH defines aging assets and end of life assets.

<u>Response:</u>

	Quantity
Overhead Wire	338 km
Underground Wire	142 km
Municipal Substations	13
Poles	8,000
Transformers	2,300

Aging assets are reviewed against expected useful life as determined by Welland Hydro (KPGM consultants) in 2012 taking into account the Kinetrics report. End of Life assets are evaluated on years in service along with other inspection and test data to determine asset replacement timing.

1.0-Energy Probe-6
References: Revised Exhibit 1, Table 1-10; Table 4-9, Form 2K;
Revised Exhibit 4, Page 28

Preamble: WHESC is currently reviewing the management employee compensation evaluation process for the 2017 Test Year to better align with "RRFE" performance metrics. The structure is updated annually with salary increases based upon market Hay All Industrial with one year lagging for management staff using the P50 line, and ability to pay.

a) For the Executive/Management Positions please provide for 2013-2017:
- **A List of Positions and Titles, distinguishing Executive and Management.**
- **The Average Salaries and Total Compensation for each of Executive and Management (aggregate).**

Response:

Welland Hydro is a very small utility. There are only (4) executive positions and (9) management positions. The titles for the executive positions are:

President & CEO
Chief Operating Officer & Director of Finance
Director of Engineering & Operations
Director of Customer Service & Employee Relations

The titles for the management positions are as follows:

Corporate Secretary/Privacy Officer/Executive Assistant
Billing Supervisor/MDMR Administrator
Billing Assistant/Payroll
Business & Regulatory Analyst
Senior Accountant
Senior Engineer
Field Supervisor
Operations Supervisor & Safety Officer
Customer Service & Conservation and Demand Manager

The total compensation paid to all executive and management positions is $1,528,126 for an average of $117,548. On average executives earn 41% above this average and management positions earn 18% less than the average.

b) Please provide a summary of the latest Hay and MEARIE Compensation Benchmarking Studies related to these positions, including the Peer Group(s).

Response:

See 4-SEC-17

c) For the Executive and Management positions, please provide a summary of the management employee compensation evaluation process for the 2017 Test Year related to Performance Pay (Short Term Incentive Pay-STIP), including sample scorecard(s).

Response:

See Response to part (d).

d) For 2013-2016, please indicate if WH paid performance pay and the average awards as a percentage of Base Pay.

Response:

Welland Hydro currently does not award performance pay incentives to its employees.

e) Based on the response to part a) please explain why Executive/Management Salaries and Incentives has increased for 14 positions from $1,385,904 in 2013 to $1,528,126 in 2017.

Response:

Similar to the response to 4-SEC-16(e) Welland Hydro has produced a Table below which identify the change in mix of management personnel. The 2013 COS Rate Application had three junior positions which have been either eliminated or changed. The accounting assistant has been replaced with a designated CPA for succession planning and IFRS. A management position in Customer Service has been replaced in the management FTE count with a senior engineer. The reduction of one FTE was from outsourcing of a junior IT position. As indicated in the rate application there were positions in management which were not at 100% base pay in the 2013 COS who have received pay grade increases from 2013 to 2017.

2013 COS				2017 Test				
$	FTE	$/FTE		$	FTE	$/FTE		%
$1,189,763	11	$108,160		$1,349,760	11	$122,705		13.45%
197,141	3	65,714		178,366	2	89,183		35.71%
$1,386,904	14	$99,065		$1,528,126	13	$117,548		19.33%

f) After operating with 12 Executive/Management positions in 2014-2016 why is another senior position required in 2017?

Response:

In 2017, Welland Hydro has added a management engineering position for succession planning and enhancing assets management processes. As indicated in the application, Welland Hydro has eliminated a vehicle mechanic to offset this addition resulting in no change to FTEs.

1.0-Energy Probe-7
Reference: Revised Exhibit 1, Pages 76-78, Tables 1-23, 1-24

Preamble: WHESC has consistently showed year over year improvements in its three-year efficiency performance metric since 2013.

a) Please explain why WH has not targeted an Efficiency Assessment performance Target in Group 1. Specifically, why it cannot "up its game" to move into Group 1.

Response:

Welland Hydro has submitted a PEG forecast module with this application that shows increased efficiency based on figures derived from the 2017 Test Year. Welland Hydro will continue to monitor actual results during the 2017-2021 period with a goal towards continuous improvement.

b) Please explain why the performance targets for cost per customer ($518) and Cost/km of line ($24,917) are set above recent averages.

Response:

The targets set for 2017 for cost per customer and cost/km are derived from the PEG forecast module. The targets reflect increases to OM&A such as increased OEB assessment fees, locate costs, and succession planning. Prior periods also include reductions in OM&A due to vacancies such as maternity leaves. The 2014 and 2015 years would not include COS rate application costs which have increased significantly due to increased customer engagement.

c) Please explain why with customer growth averaging about 1%/year, total cost/customer should not match/mirror growth.

Response:

See response to 1-SEC-9 (d).

d) Please provide the projected Targets for 2017-2021 if these differ from those in Table 1-23.

Response:

Table 1-23 Column-Performance Improvement Targets reflect projections for the 2017 Test Year. Welland Hydro's current budgeting process does not extend past 2017 with the exception of capital spending. Even if the PEG forecasting model extended out past the 2017 Test Year, data is not available to forecast targets.

e) Also, please explain why forward 2017-2021 targets are not in the Business Plan Pages 3 and 4.

<u>Response:</u>

See response to (d) above.

1.0-Energy Probe-8
Reference: Revised Exhibit 1, Page 81, Table 1-26

a) Please discuss why WH Liquidity and Leverage ratios are declining and not forecast to improve.

Response:

Liquidity ratios began declining in 2013 when the third-party debt with TD Canada Trust was moved from long to short term as it matured February 1, 2014. Liquidity ratios have been stable since the third-party loan was paid off in 2014. Welland Hydro's liquidity ratio has been stable since 2013 as can be seen in the forecasted 2016 scorecard in response to 1-VECC-4 above. The re-payment of the TD Canada Loan in 2014 actually improved the leverage ratio which has remained stable thru 2016 which can also be seen in the 2016 forecasted scorecard.

b) Specifically, provide an exhibit and explanatory notes that shows/discusses the impact of WH dividend policy on the ratios using pre-and post-Net Income data.

Response:

Welland Hydro's dividend policy was submitted in response to 1-VECC 8 (b) above. In response to 1-VECC- 8 (a) above Welland Hydro submitted an analysis showing Net Income data and dividends and the associate changes to Retained Earnings per year. If Welland Hydro did not pay out any dividends during the period analyzed it would have an estimated liquidity ratio of 1.87 in 2016, and an estimated leverage ratio of .70 in 2016.

c) Please provide in tabular form the allowed and actual ROE for the period 2011-2016.

Response:

Actual ROE from 2011 to 2016 can also be seen in the 2016 forecasted scorecard in response to 1-VECC-4 above.

d) Please Explain how the interest on the $5.6 million in Notional debt held by the City of Welland is dealt with e.g. as a Component of the annual Shareholder Dividend?

Response:

The Long Term note with the City of Welland is for $13.5 million at 6.25%. Notional debt of approximately $5.3 million (Exhibit 5) is not associated with the City of Welland or Shareholder Dividend. Notional debt is the difference between Welland Hydro's deemed and actual long term debt.

1.0-Energy Probe-9
Reference: Appendix 1-G Innovative Research Group Inc. Survey Report
Pages 12-13 and 38-40

a) **Please explain why the Residential Customer Participation surveys /targeting numbers were so low (Telephone and Focus Groups).**

Response:

Residential customer participation in the focus groups and telephone survey were not deemed “low” by either WHESC or its consultant, Innovative Research Group. Welland Hydro had 501 residential customers respond to the survey, which is accurate to +/- 4.3 percentage points, 19 times out of 20.

b) **Please compare the demographic profiles of the actual participants with those of the general WH customer base.**

Response:

For most utilities, the only known customer base characteristics are **geography, electricity usage**, and **rate class**. Like almost all other Ontario LDCs, WHESC doesn’t have a detailed demographic profile of its customers.

One approach which the OEB has accepted for rate applications under the RRFE – is a **stratified random sampling approach** based on known characteristics of customer bases such as region (where applicable) and **consumption by rate classes of low-volume consumers**. This concept of dividing the customer sample into quartiles based on electricity consumption is only to develop accurate quotas to ensure the sample is representative of an LDC’s low volume customer base.

WHESC’s two surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In both surveys, residential and general service customers were divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households.

The following table illustrates the segmentation of the residential and general service customer survey samples by usage quartile. Note due to the sample size, general service customers were not subdivided into smaller groups.

Customer Type		Total Sample	Low	Medium-Low	Medium-High	High
Residential	Target	500	125	125	125	125
	Actual	501	125	125	126	125
	Difference	+1	0	0	+1	0
General service	Target	NA				
	Actual	25				
	Difference	NA				

Note on low response rate for GS under 50 kW: The sample for the general service survey was drawn from a list of **958** which was provided to INNOVATIVE by Welland Hydro. General service respondents were screened to ensure they were in charge of managing the electricity bill at their organization. General service customers were contacted on weekdays between 9am to 5pm.

While best attempts were made to survey as large a group of general service customers, given the limited available number of customers in this rate class, INNOVATIVE was only able to survey 25 general service customers.

Before retiring any randomly selected telephone number from the contact list, 8 attempts were made to reach a potential respondent for each unique telephone number, or until an interviewer received a hard refusal. Each day a new sample was released from the contact list to replace completed or retired numbers.

Focus groups are a qualitative research exercise and were designed to explore and identify varying opinions participants (i.e. in this case, low-volume customers) have towards WHESC's DSP and rate implications. Participants were randomly recruited to these focus groups from WHESC's billing database. Randomization ensured WHESC had a good mix of customers representing their broader customer base.

c) Please provide the Survey Sample Statistics.

Response:

INNOVATIVE conducted two customer surveys by telephone for Welland Hydro:

1. A residential customer survey conducted among **501 respondents** between August 5th and August 11th, 2016.
2. A general service customer survey conducted among **25 respondents** between August 8th and August 17th, 2016.

Respondents were randomly selected from customer lists provided by Welland Hydro (18,216 residential records and 958 general service records).

- A sample of 501 residential customers is considered accurate to within ±4.3 percentage points, 19 times out of 20.
- A sample of 25 general service customers is considered accurate to within ±19.4 percentage points, 19 times out of 20 (*due to the size of the margin of error on general service customers, these results should be interpreted as directional only*).

The margin of error in both surveys will be larger within each sub-grouping of the samples.

d) Specifically, explain why random sampling was used and why were Vulnerable customers (Seniors Low Income and Renters) not Targeted.

<u>Response:</u>

A stratified random sampling approach was used to provide accurate representation of WHESC's actual customer base.

A proxy for "vulnerable customers" was both identified and analyzed within WHESC telephone survey reporting (see "Financially Strained Households" segmentation pg.39 and its reference through the report).

Financial Strain and Level of Acceptance: How does the state of a respondent's finances affect permission for a rate increase? In other words, are customers struggling to get by less likely to give permission than those who are financially secure?

INNOVATIVE measured this "financial strain" through the following customer input statement:

> *The cost of my electricity bill has a major impact on my finances and requires that I do without some other important priorities.*

Those who agreed were considered to be "financially strained"; those that disagreed were considered "not financially strained".

While a strong majority (84%) of "not financially strained" residential households give permission, just two-in-three (66%) of the "financially strained" households give permission.

Figure 24: Financial Flexibility and Level of Acceptance

	Financially Strained Households	Not Financially Strained Households
The rate increase is reasonable and I support it	25%	48%
I don't like it, but I think the rate increase is necessary	41%	36%
The rate increase is unreasonable and I oppose it	29%	12%
Overall Permission	**66%**	**84%**

Note: 'Don't know'/'Refused' not shown

1.0-Energy Probe-10
References: Appendix 1-G Innovative Research Group Inc. Survey Report Page 43, Figure 3 and Page 100

Preamble: Welland Hydro's proposed plan will see it spend an estimated $36.4 million on on-going maintenance and the operation of the distribution system; and invest an estimated $12.1 million in new equipment and infrastructure priorities that will help ensure system reliability. To fund this plan, Welland Hydro is proposing the average general service customer's rates increase by approximately $1.77 per month on the distribution portion of their bill over the next five years. So, in five years, by 2021, the average general service organization will be paying an estimated $8.87 more per month on the distribution portion of its electricity bill.

a) **Please explain, in more detail why, given the overwhelming desire for lower bills, the trade-offs between lower bills/lower investment and vice-versa in the context of the proposed 2017 revenue requirement increase, was not tested in more detail by proposing alternative Scenarios.**

Response:

WHESC believes that after our customer engagement activities, that the overwhelming desire for lower bills lays primarily with costs drivers outside of the utility's control, namely the commodity cost of electricity. When asked for permission to proceed with the proposed plan, 71% of residential customer provide WHESC with social permission to proceed with the level of spending and investments – as detailed in this rate application and the customer engagement consultation – needed to maintain and operate the distribution system.

WHESC had completed the substantive portion of if customer engagement prior to the OEB's issuance of its Handbook for Utility Rate Applications (October 2016). Had the Handbook been issued before WHESC's customer engagement, it would have likely tested trade-offs between lower bills and lower investments.

In future customer engagements, WHESC will follow the Handbook by defining outcomes that customers value, incorporate these outcomes into its business plan and test alternative investment scenarios linked to delivering on customer defined outcomes.

b) **Did Innovative propose such customer value questions/scenarios be presented and what was the utility response?**

Response:

Should WHESC not have received a majority of customers providing it with "social permission" to proceed with its plan base on this scenario; the possibility of re-engaging with customers under an alternative scenario was always a possibility.

Seeing as how 71% of residential customers provided social permission, WHESC believed at the time, reengaging customers with alternative scenarios was not necessary for this rate application.

- **Recall**: A strong majority (71%) of residential customers accept the rate increase. 34% think it's reasonable and support it, 38% would accept it but don't like it, and 23% think it's unreasonable and oppose it.

Exhibit 2 – Rate Base

Board Staff – Exhibit 2

2-Staff-12
Ref: Ex.2, Page 5, Table 2-1 – Summary of Rate Base

Welland Hydro's rate base for the 2017 test year is forecast to increase by approximately 7% from the 2013 OEB-approved amount.

a) In its annual capital planning and implementation for the years 2013 to 2016, did Welland Hydro take into account the cumulative impact its capital expenditures would have on rate base, rates and customer impact in 2017? If so how? Please describe.

Response:

Welland Hydro did take into account forecasted capital expenditure levels when estimating the rate impacts for the 2017 Test Year. As a result of this analysis, two full time FTEs were eliminated and a vehicle mechanic position was eliminated to provide for hiring an engineering position.

b) How did this inform the pacing of investments identified in the Distribution System Plan for 2017 forward?

Response:

Welland Hydro's capital spending is first based upon a review of existing assets which are prioritized by year based upon anticipated replacement dates. A second review is then done to evaluate the capital expenditure requirements each year. Welland Hydro then reviews the total spending in each year and attempts to smooth the capital spending over the forecast period. If smoothing is required, the first category to be reviewed would be General Plant. Any further balancing of capital expenditures over the forecast period would be made to System Renewal Projects. Further reviews will be necessary after each year within the DSP as there will always be unexpected replacement of assets which have not been planned.

2-Staff-13
Cost of Power Calculations
Ref: Table 2.23 Cost of Power Calculation, Page 37

Please update the Cost of Power calculation with the updated Rural and Remote Rate Protection rate for 2017 of $0.0021/kWh.

<u>Response:</u>

Welland Hydro updated the 2017 Cost of Power to reflect the following: change in rural and remote rate protection rate for 2017, revised RPP and Non-RPP for 2017, and revised customer counts and volumes resulting from responses to interrogatories. Please see the Table below for the updated 2017 Cost of Power.

Details	Metric	2017 Forecast kWh/kW	Loss Factor Proposed	2017 Uplifted kWh	2017 Rates	2017 Cost of Power
Electricity - Commodity RPP						
Residential	kWh	149,251,286	1.0476	156,355,647	0.11239	17,572,811
General Service < 50kW	kWh	44,090,107	1.0476	46,188,796	0.11239	5,191,159
General Service 50 to 4,999 kW	kWh	12,020,556	1.0457	12,569,810	0.11239	1,412,721
Direct Market Participant	kWh	0	1.0476	0	0.11239	0
Street Lighting	kWh	0	1.0476	0	0.11239	0
Sentinel Lighting	kWh	726,268	1.0476	760,838	0.11239	85,511
Unmetered Scattered Load	kWh	786,533	1.0476	823,972	0.11239	92,606
Total RPP		**206,874,749**		**216,699,062**		**24,354,807**
Electricity - Commodity Non-RPP						
Residential	kWh	8,928,964	1.0476	9,353,983	0.10709	1,001,718
General Service < 50kW	kWh	7,495,760	1.0476	7,852,558	0.10709	840,930
General Service 50 to 4,999 kW	kWh	118,902,029	1.0457	124,335,852	0.10709	13,315,126
Direct Market Participant	kWh	3,164,185	1.0476	3,314,800	0.00000	0
Street Lighting	kWh	1,286,433	1.0476	1,347,667	0.10709	144,322
Sentinel Lighting	kWh	23,169	1.0476	24,272	0.10709	2,599
Unmetered Scattered Load	kWh	177,292	1.0476	185,731	0.10709	19,890
Total Non-RPP		**139,977,833**		**146,414,862**		**15,324,586**
Total Power USoA 4705		**346,852,582**		**363,113,924**		**39,679,392**
Wholesale Market Service						
Residential	kWh	158,180,250	1.0476	165,709,630	0.00360	596,555
General Service < 50kW	kWh	51,585,867	1.0476	54,041,354	0.00360	194,549
General Service 50 to 4,999 kW	kWh	130,922,585	1.0008	131,027,009	0.00360	471,697
Direct Market Participant	kWh	3,164,185	1.0476	3,314,800	0.00000	0
Street Lighting	kWh	1,286,433	1.0476	1,347,667	0.00360	4,852
Sentinel Lighting	kWh	749,437	1.0476	785,110	0.00360	2,826
Unmetered Scattered Load	kWh	963,825	1.0476	1,009,703	0.00360	3,635
Total Wholesale Market Service Charge		**346,852,582**		**357,235,272**		**1,274,114**
Rural Rate Protection						
Residential	kWh	158,180,250	1.0476	165,709,630	0.00210	347,990
General Service < 50kW	kWh	51,585,867	1.0476	54,041,354	0.00210	113,487
General Service 50 to 4,999 kW	kWh	130,922,585	1.0008	131,027,009	0.00210	275,157
Direct Market Participant	kWh	3,164,185	1.0476	3,314,800	0.00210	6,961
Street Lighting	kWh	1,286,433	1.0476	1,347,667	0.00210	2,830
Sentinel Lighting	kWh	749,437	1.0476	785,110	0.00210	1,649
Unmetered Scattered Load	kWh	963,825	1.0476	1,009,703	0.00210	2,120
Total Rural Rate Protection		**346,852,582**		**357,235,272**		**750,194**
Ontario Electricity Support Program						
Residential	kWh	158,180,250	1.0476	165,709,630	0.00110	182,281
General Service < 50kW	kWh	51,585,867	1.0476	54,041,354	0.00110	59,445
General Service 50 to 4,999 kW	kWh	130,922,585	1.0008	131,027,009	0.00110	144,130
Direct Market Participant	kWh	3,164,185	1.0476	3,314,800	0.00000	0
Street Lighting	kWh	1,286,433	1.0476	1,347,667	0.00110	1,482
Sentinel Lighting	kWh	749,437	1.0476	785,110	0.00110	864
Unmetered Scattered Load	kWh	963,825	1.0476	1,009,703	0.00110	1,111
Total Ontario Electricity Support Program		**346,852,582**		**357,235,272**		**389,313**
Total WMS/RPP/OESP USoA 4708						**2,413,620**
Transmission Network						
Residential	kWh	158,180,250	1.0476	165,709,630	0.00770	1,275,964
General Service < 50kW	kWh	51,585,867	1.0476	54,041,354	0.00680	367,481
General Service 50 to 4,999 kW	kW	377,726	1.0000	377,726	2.31440	874,209
Street Lighting	kW	1,782	1.0000	1,782	2.16230	3,853
Sentinel Lighting	kW	2,061	1.0000	2,061	2.16700	4,466
Unmetered Scattered Load	kWh	963,825	1.0476	1,009,703	0.00680	6,866
Total Transmission Network UsoA 4714						**2,532,839**
Transmission Connection						
Residential	kWh	158,180,250	1.0476	165,709,630	0.00600	994,258
General Service < 50kW	kWh	51,585,867	1.0476	54,041,354	0.00510	275,611
General Service 50 to 4,999 kW	kW	377,726	1.0000	377,726	1.99480	753,488
Street Lighting	kW	3,582	1.0000	3,582	1.64120	5,879
Sentinel Lighting	kW	2,061	1.0000	2,061	1.64480	3,390
Unmetered Scattered Load	kWh	963,825	1.0476	1,009,703	0.00510	5,149
Total Transmission Connection UsoA 4716						**2,037,775**
Smart Meter Entity Charge						
Residential	Customers	21,025	12.0000	252,300	0.79000	199,317
General Service < 50kW	Customers	1,777	12.0000	21,324	0.79000	16,846
Total Smart Meter Entity UsoA 4751						**216,163**
Total Cost of Power						**46,879,790**

2-Staff-14
Ref: Ex.2, Page 47, Table 2-26A-Table 2-26D – Capital Projects

Welland Hydro has provided a list of 2017 capital projects. The total Test Year 2017 capital expenditure for all projects is $2,413,986.

a) Do all of the projects, and related capital expenditures that are listed in Tables 2-26A-D, continue to be expected to be placed into service in 2017 and to be added to the 2017 Rate Base?

Response:

All projects are planned to be placed into service in 2017.

b) If some of the projects that are listed are not expected to be in-service in 2017 and as a result will not be added to the 2017 Rate Base, please identify all such projects, the associated capital expenditure and the expected in-service date.

Response:

Not applicable.

c) Please provide year-to-date actuals for capital projects in the same format as Tab 2-AA of the chapter 2 appendices and the net book value of fixed assets (i.e. Tab 2-BA Fixed Asset Continuity Schedule).

Response:

Welland Hydro has revised appendices 2-AA to reflect 2016 Actuals and revisions to the 2017 Test Year. Welland Hydro has also revised 2-BA for 2016 Actuals and the 2017 Test Year. Please see Tables below.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	2016

			Cost						**Accumulated Depreciation**						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**		**Deferred Revenue**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**		**Deferred Revenue**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 897,969			$ 69,027		$ 966,996	-$ 574,097			-$ 103,747		-$ 677,844	$ 289,152
CEC	1612	Land Rights (Formally known as Account 1806)	$ 70,296					$ 70,296	-$ 61,551			-$ 640		-$ 62,191	$ 8,105
N/A	1805	Land	$ 158,686					$ 158,686	$ -			-$ 1,236		-$ 1,236	$ 157,450
47	1808	Buildings	$ 96,568					$ 96,568	-$ 63,701					-$ 63,701	$ 32,867
13	1810	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359					$ 467,359	-$ 82,418			-$ 14,857		-$ 97,275	$ 370,084
47	1820	Distribution Station Equipment <50 kV	$ 4,164,765			$ 326,496		$ 4,491,261	-$ 2,597,051			-$ 84,678		-$ 2,681,729	$ 1,809,532
47	1825	Storage Battery Equipment	$ -					$ -	$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,283,201			$ 693,263		$ 9,976,464	-$ 1,593,623			-$ 181,091		-$ 1,774,714	$ 8,201,750
47	1835	Overhead Conductors & Devices	$ 13,417,623			$ 345,044		$ 13,762,667	-$ 8,686,500			-$ 137,826		-$ 8,824,326	$ 4,938,341
47	1840	Underground Conduit	$ 1,318,104			$ 224,726		$ 1,542,830	-$ 192,696			-$ 27,340		-$ 220,036	$ 1,322,794
47	1845	Underground Conductors & Devices	$ 11,193,215			$ 243,389		$ 11,436,604	-$ 7,612,892			-$ 180,461		-$ 7,793,353	$ 3,643,251
47	1850	Line Transformers	$ 6,941,437			$ 323,972	-$ 67,132	$ 7,198,277	-$ 3,548,166			-$ 120,896	$ 47,047	-$ 3,622,015	$ 3,576,262
47	1855	Services (Overhead & Underground)	$ 859,971			-$ 4,409		$ 855,562	-$ 175,894			-$ 20,260		-$ 196,154	$ 659,408
47	1860	Meters	$ 38,777			$ -	$ -	$ 38,777	-$ 38,777					-$ 38,777	$ -
47	1860	Meters (Smart Meters)	$ 3,016,950			$ 68,546	-$ 52,396	$ 3,033,100	-$ 1,140,360			-$ 203,410	$ 24,780	-$ 1,318,990	$ 1,714,110
N/A	1865	Other Installations on Customer Premises	$ -					$ -	$ -					$ -	$ -
N/A	1905	Land	$ -					$ -	$ -					$ -	$ -
47	1908	Buildings & Fixtures	$ 2,555,397			$ 80,154		$ 2,635,551	-$ 1,232,023			-$ 77,410		-$ 1,309,433	$ 1,326,118
13	1910	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,446					$ 90,446	-$ 72,706			-$ 5,676		-$ 78,382	$ 12,064
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 251,753			$ 20,730	-$ 37,660	$ 234,823	-$ 108,357			-$ 52,305	$ 37,660	-$ 123,002	$ 111,821
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -					$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -					$ -	$ -
10	1930	Transportation Equipment	$ 1,704,481			$ 716,461	-$ 242,367	$ 2,178,575	-$ 1,183,269			-$ 84,573	$ 237,719	-$ 1,030,123	$ 1,148,452
8	1935	Stores Equipment	$ 30,023					$ 30,023	-$ 30,023					-$ 30,023	$ -
8	1940	Tools, Shop & Garage Equipment	$ 83,043			$ 17,771		$ 100,814	-$ 70,838			-$ 5,720		-$ 76,558	$ 24,256
8	1945	Measurement & Testing Equipment	$ 20,451					$ 20,451	-$ 16,048			-$ 771		-$ 16,819	$ 3,632
8	1950	Power Operated Equipment	$ -					$ -	$ -					$ -	$ -
8	1955	Communications Equipment	$ 298,231					$ 298,231	-$ 160,313			-$ 28,678		-$ 188,991	$ 109,240
8	1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -					$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235					$ 315,235	-$ 114,935			-$ 11,128		-$ 126,063	$ 189,172
47	1970	Load Management Controls Customer Premises	$ -					$ -	$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -					$ -	$ -					$ -	$ -
47	1980	System Supervisor Equipment	$ 776,733			$ 3,231		$ 779,964	-$ 564,083			-$ 42,265		-$ 606,348	$ 173,616
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -					$ -	$ -
47	1995/2440	Contributions & Grants/Deferred Revenue	-$ 511,181		$ 511,181			$ -	$ 11,093		-$ 11,093			$ -	$ -
47	2440	Deferred Revenue[5]	$ -		-$ 511,181	-$ 207,255		-$ 718,436	$ -		$ 11,093	$ 19,253		$ 30,346	-$ 688,090
		Sub-Total	**$ 57,539,532**	**$ -**	**$ -**	**$ 2,921,146**	**-$ 399,555**	**$ 60,061,123**	**-$ 29,909,231**	**$ -**	**$ -**	**-$ 1,365,715**	**$ 347,206**	**-$ 30,927,740**	**$ 29,133,384**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 57,539,532**	**$ -**	**$ -**	**$ 2,921,146**	**-$ 399,555**	**$ 60,061,123**	**-$ 29,909,231**	**$ -**	**$ -**	**-$ 1,365,715**	**$ 347,206**	**-$ 30,927,740**	**$ 29,133,384**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total										**-$ 1,365,715**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,365,715

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	2017

			Cost						Accumulated Depreciation						
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance			Additions [4]	Disposals [6]	Closing Balance	Opening Balance			Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 966,996					$ 966,996	-$ 677,844			-$ 87,159		-$ 765,003	$ 201,993
CEC	1612	Land Rights (Formally known as Account 1806)	$ 70,296					$ 70,296	-$ 62,191			-$ 640		-$ 62,831	$ 7,465
N/A	1805	Land	$ 158,686					$ 158,686	-$ 1,236					-$ 1,236	$ 157,450
47	1808	Buildings	$ 96,568					$ 96,568	-$ 63,701			-$ 1,236		-$ 64,937	$ 31,631
13	1810	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359					$ 467,359	-$ 97,275			-$ 14,857		-$ 112,132	$ 355,227
47	1820	Distribution Station Equipment <50 kV	$ 4,491,261			$ 170,000		$ 4,661,261	-$ 2,681,729			-$ 92,319		-$ 2,774,048	$ 1,887,213
47	1825	Storage Battery Equipment	$ -					$ -	$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,976,464			$ 743,218		$ 10,719,682	-$ 1,774,714			-$ 195,456		-$ 1,970,170	$ 8,749,512
47	1835	Overhead Conductors & Devices	$ 13,762,667			$ 115,000		$ 13,877,667	-$ 8,824,326			-$ 142,427		-$ 8,966,753	$ 4,910,914
47	1840	Underground Conduit	$ 1,542,830			$ 225,000		$ 1,767,830	-$ 220,036			-$ 31,838		-$ 251,874	$ 1,515,956
47	1845	Underground Conductors & Devices	$ 11,436,604			$ 280,000		$ 11,716,604	-$ 7,793,353			-$ 189,184		-$ 7,982,537	$ 3,734,067
47	1850	Line Transformers	$ 7,198,277			$ 435,000		$ 7,633,277	-$ 3,622,015			-$ 130,383		-$ 3,752,398	$ 3,880,879
47	1855	Services (Overhead & Underground)	$ 855,562			$ 40,000		$ 895,562	-$ 196,154			-$ 20,705		-$ 216,859	$ 678,703
47	1860	Meters	$ 38,777					$ 38,777	-$ 38,777					-$ 38,777	$ -
47	1860	Meters (Smart Meters)	$ 3,033,100			$ 60,000	-$ 60,000	$ 3,033,100	-$ 1,318,990			-$ 203,872	$ 34,680	-$ 1,488,182	$ 1,544,918
N/A	1865	Other Installations on Customer Premises	$ -					$ -	$ -					$ -	$ -
N/A	1905	Land	$ -					$ -	$ -					$ -	$ -
47	1908	Buildings & Fixtures	$ 2,635,551			$ 100,000		$ 2,735,551	-$ 1,309,433			-$ 68,503		-$ 1,377,936	$ 1,357,615
13	1910	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,446					$ 90,446	-$ 78,382			-$ 3,896		-$ 82,278	$ 8,168
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 234,823			$ 15,000		$ 249,823	-$ 123,002			-$ 53,238		-$ 176,240	$ 73,583
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -					$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -					$ -	$ -
10	1930	Transportation Equipment	$ 2,178,575			$ 35,000	-$ 35,423	$ 2,178,152	-$ 1,030,123			-$ 109,268	$ 35,423	-$ 1,103,968	$ 1,074,184
8	1935	Stores Equipment	$ 30,023					$ 30,023	-$ 30,023					-$ 30,023	$ -
8	1940	Tools, Shop & Garage Equipment	$ 100,814			$ 5,000		$ 105,814	-$ 76,558			-$ 5,828		-$ 82,386	$ 23,428
8	1945	Measurement & Testing Equipment	$ 20,451					$ 20,451	-$ 16,819			-$ 771		-$ 17,590	$ 2,861
8	1950	Power Operated Equipment	$ -					$ -	$ -					$ -	$ -
8	1955	Communications Equipment	$ 298,231					$ 298,231	-$ 188,991			-$ 28,678		-$ 217,669	$ 80,562
8	1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -					$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235					$ 315,235	-$ 126,063			-$ 11,128		-$ 137,191	$ 178,044
47	1970	Load Management Controls Customer Premises	$ -					$ -	$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -					$ -	$ -					$ -	$ -
47	1980	System Supervisor Equipment	$ 779,964			$ 80,000	-$ 50,000	$ 809,964	-$ 606,348			-$ 48,096	$ 50,000	-$ 604,444	$ 205,520
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -					$ -	$ -
47	1995/2440	Contributions & Grants/Deferred Revenue	$ -					$ -	$ -					$ -	$ -
47	2440	Deferred Revenue[5]	-$ 718,436			-$ 25,000		-$ 743,436	$ 30,346			$ 22,701		$ 53,047	-$ 690,389
		Sub-Total	**$ 60,061,123**	**$ -**	**$ -**	**$ 2,278,218**	**-$ 145,423**	**$ 62,193,918**	**-$ 30,927,740**	**$ -**	**$ -**	**-$ 1,416,781**	**$ 120,103**	**-$ 32,224,418**	**$ 29,969,501**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***						$ -						$ -	$ -
		Total PP&E	**$ 60,061,123**	**$ -**	**$ -**	**$ 2,278,218**	**-$ 145,423**	**$ 62,193,918**	**-$ 30,927,740**	**$ -**	**$ -**	**-$ 1,416,781**	**$ 120,103**	**-$ 32,224,418**	**$ 29,969,501**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total										**-$ 1,416,781**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,416,781

Appendix 2-AA
Capital Projects Table

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2016 Actual Year	2017 Test Year	2017 Test Year Revised	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access												
Municipal Relocations												
Woodlawn Road Widening Rice to First Avenue	287,848											
Contributed Capital Region of Niagara - Woodlawn	-124,159											
Wellington Street Road Widening				32,821								
Contributed Capital City of Welland - Wellington					-3,000	-3,783						
System Expansion - Generation							14,501	14,501				
Sub-Total Municipal Relocations	**163,689**	**0**	**0**	**32,821**	**-3,000**	**-3,783**	**14,501**	**14,501**	**0**	**0**	**0**	**0**
Customer Connections												
New Overhead/Underground Service Connections	**39,404**	**9,908**	**40,922**	**42,577**	**40,000**	**-30,600**	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**
Expansions (Subdivisions)												
Clare Estates 1	9,160											
Elmwood Estates	28,368											
Hunter's Pointe - Galloway	26,515											
Hunter's Pointe - Block 150	2,316											
Shipview Court	10,175											
Webber Estates		28,503										
Blue Rive Estates		16,214										
Hunter's Pointe - Masters		9,864										
Hunter's Pointe - Highlands		14,820										
Coyle Creek 2 & 3			6,800									
Pine Creek			6,919									
Clare Estates 2			1,902									
Coyle Creek 4			8,112									
Tetherwood 2			6,583									
Michael Drive				4,230								
Clare Estates 3				10,068								
Lochness North 1				10,112								
Forest Creek Subdivision						3,120						
Woodview Subdivision						12,378						
Coyle Creek 6						10,597						
Sub Total Subdivisions - Plan	**76,534**	**69,401**	**30,316**	**24,410**	**50,000**	**26,095**	**50,000**	**25,000**	**50,000**	**50,000**	**50,000**	**50,000**
Expansions (Transformers/Meters)												
Contributed Capital Sale of Transformers/Meters	**-74,519**	**-59,359**	**-29,240**	**-56,586**	**0**	**-69,968**	**0**	**0**	**0**	**0**	**0**	**0**
Retail Meters												
Smart Meters	17,202	65,532	63,482	50,857	60,000	68,545	100,000	60,000	100,000	100,000	100,000	60,000
Communication Equipment - Metro Collector	3,456											
Computer Equipment - Smart Meter Diagnostics			5,873									
MIST Meter Replacements									60,000	60,000		
Sub-Total Retail Meters	**20,658**	**65,532**	**69,355**	**50,857**	**60,000**	**68,545**	**100,000**	**60,000**	**160,000**	**160,000**	**100,000**	**60,000**
Sub-Total System Access	**225,766**	**85,482**	**111,353**	**94,079**	**147,000**	**-9,711**	**204,501**	**139,501**	**250,000**	**250,000**	**190,000**	**150,000**

Appendix 2-AA
Capital Projects Table

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2016 Actual Year	2017 Test Year	2017 Test Year Revised	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Renewal Projects												
Substation Renewal												
MS 3 Battery Charger Replacement				8,227								
MS 4 Primary Cabling		3,532										
MS 5 Fencing	6,627											
MS 5 HV Switchgear - 5T2	46,065											
MS 5 HV Switchgear - 5T1				51,032								
MS 5 HV Transformer - 5T2						77,684						
MS 6 Transformer & Primary Cabling	100,995											
MS 7 Switchgear & Primary Cabling	828				200,000	248,812						
MS 8 Transformer/Switchgear/Primary Cabling							50,000	50,000	100,000	100,000		
MS 9 Switchgear & Primary Cabling										50,000	50,000	100,000
MS 10 HV Switchgear & Primary Cabling									125,000			
MS 12 Transformer & Primary Cabling	47,270			30,290								
MS 14 Transformer/Switchgear/Primary Cabling				48,350			120,000	120,000				
Sub-Total Substation Renewal	**201,785**	**3,532**	**0**	**137,899**	**200,000**	**326,496**	**170,000**	**170,000**	**225,000**	**150,000**	**50,000**	**100,000**
Overhead Line Renewal												
Pole Replacement 4.16kV First Ave-College Park to Woodland	37,692											
Pole Replacement 4.16kV Summitt Ave	17,011											
Aqueduct Area 4.16kV Rebuild-Birch,Cedar,Beechwood	73,440											
Pole Replacement 4.16kV Market Square	17,473											
Regent Street Rebuild/Conversion 2.4kV to 16kV	292,255											
Mayfair Estates Rebuild/Conversion 2.4kV to 16kV	69,810											
Niagara Street South of Quaker Rebuild/Conversion 4.16kV to 27.6kV	33,324											
Plymouth Road-St. Mary's School Rebuild/Conversion 4.16kV to 27.6kV	25,473											
Netherby Road @ Townline Tunnel Rebuild/Conversion 2.4kV to 16kV	17,375	20,185										
Maple,Bald,Denistoun,Hooker Rebuild/Conversion 4.16kV to 27.6kV	193,692	2,992										
PCB Transformer Replacements	13,660	51,238										
Cohoe Street 4.16kV Rebuild		12,538										
Pine Street 4.16kV Rebuild		28,469										
Circuit North of Crowland TS 27.6kV Rebuild		12,305										
Pole Replacement 4.16kV Woodview Estates-Trent Avenue		29,178										
Garner Avenue 4.16kV Rebuild		83,995	4,318									
Fitch Street-First Ave to Prince Charles Rebuild/Conversion 2.4kV to 16kV		31,326										
Wilton & Riverside Rebuild/Conversion 4.16kV to 27.6kV		262,157										
McCormick & Dufferin Rebuild/Conversion 2.4kV to 16kV		66,862										
Cady Street Rebuild/Conversion 2.4kV to 16kV		22,122										
Southworth Rebuild/Conversion 4.16kV to 27.6kV		335,986										
Lancaster Drive Rebuild/Conversion 4.16kV to 27.6kV		54,193										
Major Street 27.6kV Rebuild			323,827									
Division & Burger Rebuild/Conversion 4.16kV to 27.6kV			295,502									
Bald St West and Denistoun Rebuild/Conversion 2.4kV to 16kV			32,978									
Clare Avenue & Woodlawn Rebuild/Conversion 4.16kV to 27.6kV			112,907									
Harriet Street Rebuild/Conversion 2.4kV to 16kV			27,181									
Wallace Avenue Rebuild/Conversion 2.4kV to 16kV			45,980									
James Street 4.16kV Rebuild			5,393	13,477								
Orchard,Wright,Deere Rebuild/Conversion 2.4kV to 16kV			156,366	175,959		7,938						
Lincoln,Wilton,Riverside Rebuild/Conversion 4.16kV to 27.6kV			4,475	61,145								
Grange Avenue 4.16kV Rebuild				37,806		1,358						
Southworth Rebuild 8F3 Feeder				69,369								
Fitch Street & Westdale Rebuild/Conversion 2.4kV to 16kV				70,026		7,109						
Hellems Ave-King Street Conversion 4.16kV to 27.6kV				97,672								
Hellems Ave- Dorothy to Park Rebuild/Conversion 4.16kV to 27.6kV				269,045	300,000	364,989						
Fitch Street @ MS7 4.17/27.6kV Rebuild to accommodate upgrade					75,000	102,166						
Lincoln Street east of Denistoun 27.6kV Rebuild					50,000							
Church St/Niagara Street Rebuild/Conversion 4.16kV to 27.6kV					450,000	606,532	300,000	300,000				
Wellington Street-East Main to Eastdale Rebuild/Conversion 4.16kV to 27.6kV					88,000	48,742	250,000	250,000				
Bradley Ave 4.16kV Rebuild to accommodate Robert St U/G							49,485	49,485				
Ross Street/Kennedy Street Rebuild/Conversion 4.16kV to 27.6kV							150,000	150,000	100,000			
Ontario Road Corridor to Canal Rebuild/Conversion 4.16kV to 27.6kV									300,000			
Lincoln Street-Coventry to Schoelfield Rebuild/Conversion 4.16kV to 27.6kV										440,000		
Duncan Street-Hagar to East Main Rebuild/Conversion 4.16kV to 27.6kV						20,639				300,000	320,000	
Clare-Thorold to Steven Rebuild/Conversion 4.16kV to 27.6kV											100,000	
Dorothy Street-River Road to Ross St Rebuild/Conversion 2.4kV to 16kV											100,000	
Denistoun Street-Hooker to Welland River Rebuild/Conversion 4.16kV to 27.6kV											250,000	
Myrtle Avenue Rebuild/Conversion 4.16kV to 27.6kV											165,000	
Rusholme Road 27.6kV Rebuild												150,000
Classic/Lewis Street Rebuild/Conversion 2.4kV to 16kV												350,000
King Street-Lincoln to Regent Rebuild/Conversion 4.16kV to 27.6kV												300,000
Hellems Ave-Park to Lincoln Rebuild/Conversion 4.16kV to 27.6kV												310,000
Sub-Total Overhead Line Renewal	**791,205**	**1,013,546**	**1,008,927**	**794,499**	**963,000**	**1,159,473**	**749,485**	**749,485**	**400,000**	**740,000**	**935,000**	**1,110,000**

Appendix 2-AA
Capital Projects Table

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2016 Actual Year	2017 Test Year	2017 Test Year Revised	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Renewal Projects												
Underground Line Renewal												
Preston Place 4.16kV Rebuild	23,178											
Whiteoak Cr 4.16kV Rebuild	21,629											
McComb 4.16kV Rebuild	79,076	5,503										
Oak Street Rebuild/Conversion 2.4kV to 16kV	21,791	45,650										
Ontario Road Canal Crossing-Backup Cable		20,075										
Woodlawn/Lincoln/Division Canal Crossing-Backup Cable		41,856										
Preston,Wiltshire,McColl 4.16kV Rebuild		171,993										
Graystone Area Rebuild/Conversion 2.4kV to 16kV		17,970	380,376	54,285								
Clairmount/Bettes Rebuild/Conversion 2.4kV to 16kV		30,590	31,397									
Birch & Linwood Rebuild/Conversion 2.4kV to 16kV			38,603									
Rice Road Rebuild/Conversion 4.16kV to 27.6kV			85,950	17,256								
Humberstone/Townline Tunnel 27.6 kV Rebuild				345,567		42,550						
Regatta Drive-Primary Loop 2.4kV Rebuild				23,771								
Wilson Road to New Seniors Residence Rebuild/Conversion 4.16kV to 27.6kV				133,567								
Woodington/Champlain 2.4kV Rebuild					100,000	112,634						
Silvan/Newleaf Phase 1 Rebuild/Conversion 2.4kV to 16kV					210,000	226,709						
Maureen Ave 2.4kV Rebuild							125,000	125,000				
Riverview Drive Rebuild/Conversion 4.16kV to 27.6kV							150,000	150,000				
Robert Street Rebuild/Conversion 2.4kV to 16kV							150,000	150,000				
Silvan/Newleaf Phase 2 Rebuild/Conversion 2.4kV to 16kV							280,000	280,000				
Royal Oak 2.4kV Rebuild									160,000			
Page Drive-Whiteoak Cr 2.4kV Rebuild									250,000			
Loyalist/Lisa/Jennifer Rebuild/Conversion 2.4kV to 16kV									300,000			
Glenayr/McGill 2.4kV Rebuild										300,000		
Glen Park Drive/Court Rebuild/Conversion 2.4kV to 16kV										300,000		
Centennial Drive Rebuild/Conversion 2.4kV to 16kV										125,000		
Rolling Acres 2.4kV Rebuild											200,000	
Bridlewood/Chapel Hill Rebuild/Conversion 2.4kV to 16kV											300,000	
Apple/Brant Rebuild/Conversion 2.4kV to 16kV											125,000	
Erin & Steven Rebuild/Conversion 2.4kV to 16kV											150,000	150,000
Nottingham Ave 2.4kV Rebuild												250,000
Sub-Total Underground Line Renewal	**145,674**	**333,637**	**536,326**	**574,446**	**310,000**	**381,893**	**705,000**	**705,000**	**710,000**	**725,000**	**775,000**	**400,000**
Miscellaneous Renewal												
Miscellaneous Pole Replacements	78,259	89,289	107,968	101,094	100,000	107,142	100,000	100,000	50,000	50,000	50,000	50,000
Miscellaneous Transformer Replacements	27,771	81,026	39,399	73,031	50,000	73,474	50,000	50,000	50,000	50,000	50,000	50,000
Transformers New Developments	74,519	59,359	29,240	56,586	0	68,068	0		0	0	0	0
Change in Transformer Inventory	-128,126	-117,628	-43,991	36,030	0	-23,742	0		0	0	0	0
Miscellaneous Underground Rebuild	30,926	582	32,436	0	30,000	0	30,000	30,000	30,000	30,000	30,000	30,000
Miscellaneous Overhead Primary	11,288	41,357	0	0	30,000	0	30,000	30,000	30,000	30,000	30,000	30,000
Sub-Total Miscellaneous Renewal	**94,637**	**153,985**	**165,052**	**266,741**	**210,000**	**224,942**	**210,000**	**210,000**	**160,000**	**160,000**	**160,000**	**160,000**
Sub-Total System Renewal Projects	**1,233,301**	**1,504,700**	**1,710,305**	**1,773,585**	**1,683,000**	**2,092,804**	**1,834,485**	**1,834,485**	**1,495,000**	**1,775,000**	**1,920,000**	**1,770,000**

Appendix 2-AA
Capital Projects Table

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2016 Actual Year	2017 Test Year	2017 Test Year Revised	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Service												
Scada/Substation System Service												
Scada Switches/Remote Fault Indicators/Radio Systems	8,300	4,047		5,326		3,231	60,000	30,000	35,000	35,000	35,000	35,000
MS1 - RTU/Relay Replacements									100,000			
MS5 - RTU/Relay Replacements									75,000			
Scada SmartVU/Server Upgrade							50,000	50,000	50,000			
Scada Software ICCP			55,500	27,911								
Sub-Total System Service	**8,300**	**4,047**	**55,500**	**33,237**	**0**	**3,231**	**110,000**	**80,000**	**260,000**	**35,000**	**35,000**	**35,000**

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Capital Projects Table

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2016 Actual Year	2017 Test Year	2017 Test Year Revised	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
General Plant												
Furniture & Equipment												
Furniture & Equipment	**11,025**	**1,403**	**0**	**0**	**0**		**0**		**0**	**0**	**0**	**0**
Computer Hardware												
Computer Equipment Miscellaneous	13,289	14,809	14,064	42,657	25,000	20,729	25,000	15,000	25,000	25,000	25,000	25,000
Computer Equipment FileNexus Test Server			7,645									
Computer Equipment HP Scanners (4)			6,536									
Computer Equipment Cisco Firewall			9,705									
Computer Equipment Server/Lan/Battery Backup			45,922									
Computer Equipment Engineering Server			13,353									
Computer Equipment Engineering Plotter			7,839									
Computer Equipment Mcare Tablets (4)			7,560	8,984								
Computer Equipment Backup Server from Tape to Disk				15,683								
Sub-Total Computer Equipment	**13,289**	**14,809**	**112,624**	**67,324**	**25,000**	**20,729**	**25,000**	**15,000**	**25,000**	**25,000**	**25,000**	**25,000**
Computer Software												
Computer Software Northstar Customer Connect	11,250		3,750									
Computer Software Northstar CIS Version 6.4			42,844	-3,427								
Computer Software Northstar CIS Automation Platform				8,400								
Computer Software Northstar CIS Cognos License				5,667								
Computer Software Cayenta Financials Implementation	58,433											
Computer Software Cayenta Financials Fixed Assets Module/Upgrade				35,490	25,000	16,840						
Computer Software Cayenta Financials Cognos License						9,747						
Computer Software Spidaweb	4,411											
Computer Software Autocad	4,620											
Computer Software FileNexus Document Storage License/Modules		68,401	31,492			6,950						
Computer Software FileNexus Customer Online Forms					40,000		40,000					
Computer Software Multispeak Outage Manager		16,621										
Sub Total Computer Software - Plan	**78,714**	**85,022**	**78,086**	**46,130**	**65,000**	**33,537**	**40,000**	**0**	**50,000**	**50,000**	**50,000**	**50,000**
Communication Equipment												
Communication Equipment - New Phone System	**0**	**68,771**	**3,495**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Measurement & Testing Equipment												
Measurement & Testing Equipment	**2,996**	**-711**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Tools												
Tools	**0**	**0**	**5,980**	**0**	**5,500**	**17,771**	**5,000**	**5,000**	**5,000**	**5,000**	**5,000**	**5,000**
Automotive Equipment & Vehicles												
2013 Freightliner Double Bucket Truck		325,615										
2005 Backyard Digger & Trailer Used			32,500									
2014 Brooks Brothers Pole Trailer			23,327									
Rebuild GMC Digger Derrick Rebuild Motor (Truck 31 - 1988)			9,296									
Rebuild International Single Bucket Truck Sub frame (Truck 11 - 2000)			23,648									
2015 Nissan Van (Truck 8 - 2001)				27,099								
2015 Dump Trailer				4,400								
2016 International Double Bucket Truck (Truck 9 - 1998)				117,800	246,300	241,399						
2016 3/4 Ton Pickup Truck (Truck 3 - 1995)					40,000	27,663						
2016 1/2 Ton Pickup Truck (Truck 1 - 2000)					35,000	27,662						
2016 International Digger Derrick (Truck 31 - 1988)					315,000	301,937						
2017 1/2 Ton Pickup Truck (Truck 36 - 2000)							35,000	35,000				
2017 1/2 Ton Pickup Truck (Truck 37 - 2000)							35,000	0				
2018 3/4 Ton Pickup Truck (Truck 24 - 1997)									50,000			
2018 Forklift Replacement (Truck 43 - 2002)									50,000			
2019 3/4 Ton Pickup Truck (Truck 42 - 2005)										45,000		
2021 International Bucket Truck (Truck 11 - 2000)											120,000	250,000
2020 Passenger Van (Truck 41 - 2005)											30,000	
2020 Utility Van (Truck 44 - 2007)											40,000	
2021 3/4 Ton Pickup Truck (Truck 51 - 2010)												50,000
2022 International Digger Derrick (Truck 18 - 1990)												120,000
Sub Total Automotive Equipment & Vehicles	**0**	**325,615**	**88,771**	**149,299**	**636,300**	**598,661**	**70,000**	**35,000**	**100,000**	**45,000**	**190,000**	**420,000**
Buildings & Grounds												
Roof Replacement Administrative Office - Board Room Area	19,453											
Main Office & Conference Room Renovations	157,810											
Atrium Replacement/New Customer Service Area	134,344											
Building Renovations - Ladies Washrooms		22,167										
Building Renovations - Men's Washrooms			33,433									
Building Upgrades PDB Shed				3,425								
Building Upgrades A/C Multizone				15,285								
Building Upgrades Fire Alarm System					70,000	70,570						
Building Upgrades Security Access Control Replacement						9,584						
Building Upgrades Stair Lift to Lower Level							25,000	0				
Service Centre Parking Lot Repaving							100,000	100,000	100,000			
Building Upgrades - Plan									25,000	25,000	25,000	25,000
Service Centre Roof Replacement										250,000		
Sub-Total Buildings & Grounds	**311,607**	**22,167**	**33,433**	**18,710**	**70,000**	**80,154**	**125,000**	**100,000**	**125,000**	**275,000**	**25,000**	**25,000**
Renewables - Non Rate Regulated												
Renewable Generation Microfits	**81,719**	**-1,958**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Sub-Total General Plant	**499,350**	**515,118**	**322,389**	**281,463**	**801,800**	**750,852**	**265,000**	**155,000**	**305,000**	**400,000**	**295,000**	**525,000**
Total Before Renewable & Non-Rate Regulated	**1,966,717**	**2,109,347**	**2,199,547**	**2,182,364**	**2,631,800**	**2,837,176**	**2,413,986**	**2,208,986**	**2,310,000**	**2,460,000**	**2,440,000**	**2,480,000**
Less Renewable Generation Microfits	**-81,719**	**1,958**	**0**	**0**	**0**	**0**	**0**		**0**	**0**	**0**	**0**
Total Regulated	**1,884,998**	**2,111,305**	**2,199,547**	**2,182,364**	**2,631,800**	**2,837,176**	**2,413,986**	**2,208,986**	**2,310,000**	**2,460,000**	**2,440,000**	**2,480,000**

2-Staff-15
Ref: Ex.2, Page 40
Ref: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures

	2012	2013	2014	2015	2016 Bridge	2017 Test
System Access	$225,766	$ 85,482	$111,353	$94,079	$147,000	$204,501
System Renewal	$ 1,233,301	$ 1,504,700	$1,710,305	$1,773,585	$1,683,000	$1,834,485
System Service	$ 8,300	$4,047	$55,500	$33,237	-	$110,000
General Plant	$ 417,631	$517,076	$322,389	$281,463	$801,800	$265,000
Total	$1,884,998	$2,111,305	$2,199,547	$2,182,364	$2,631,800	$2,413,986

As seen in the table above, total capital expenditures for the past 5 years have increased. Furthermore, Welland Hydro's planned capital expenditures for overhead line renewal is approximately $750,000 and underground line renewal is approximately $705,000 in the 2017 test year. Line renewal spending will continue through the forecast period.

a) Please describe and quantify where possible the benefits that the applicant's customers will realize from this overhead and underground line renewal investment.

Response:

Customers impacted directly from the renewal projects will realize current or improved levels of reliability. Overall system reliability indices are expected to remain, on average below Welland Hydro's internal targets.

b) Please describe the alternative capital investments that were assessed and rejected in favour of the proposed capital investment.

Response:

Alternative investments related to capital investments or delay in asset replacement were considered for each capital project. The typical analysis (informal process) for an overhead project would also consider alternatives such as conversion to underground which is cost prohibitive.

2-Staff-16
Ref: Ex.2, Section 2.2.2.8 Service Quality and Reliability Performance, Table 2-30 – Service Quality and Reliability Performance, Page 64

As indicated in the table at the above reference, appointment scheduling has decreased since 2013. Please outline what Welland Hydro is doing to ensure that the trend does not bring the metric below 90%.

Response:

WHESC will periodically employ an outside contractor during busy periods to improve performance which can be seen by the increased metrics in 2016.

<u>Distribution System Plan</u>

2-Staff-17
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.1 Distribution System Plan Overview, Page 13

General plant expenditures account for just over 10% of capital expenditures for 2017. The 2017 test year marks the start of a program to improve building facilities and grounds with repaving the service center parking lot. This project will be phased in over two years.

Given the one-time nature of this expenditure, did Welland Hydro consider only allocating the two-year costs over the 5 year IRM period? If not, please explain why.

<u>Response:</u>

The repaving of the parking lot is for two distinct areas and will be replaced over a two-year period beginning in 2017. This was done to mitigate the impact to the 2017 Test Year. Welland Hydro has additional building improvements during the 2017-21 period including a roof replacement. As a result, Welland Hydro did not consider phasing the proposed repaving over the five-year period.

2-Staff-18
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.1 Distribution System Plan Overview, Page 13

System Renewal
"System Renewal projects make up the largest category of investments for 2017 and account for over 72% of total capital expenditures. Projects in this category consist of the replacement of distribution assets. Applying WHESC's asset management process, WHESC has determined many of these assets are in poor condition and susceptible to failure in the near term if not replaced. System renewal investments also address reliability and, where practical, voltage conversions which have greatly contributed to WHESC's reduced loss factor in 2017. The reduction in the loss factor from past conversion projects is expected to generate savings in customer's power and power related billings of approximately $250,000 in the 2017 Test Year."

a) Are voltage conversions the primary driver of any of the asset replacements grouped in the System Renewal category, or does this refer to voltage conversions implemented only after all or most of the affected assets have already been identified as requiring replacement due to deterioratedcondition?

Response:

Useful end of life and asset condition is the primary driver necessitating asset replacement. Projects meeting this criteria are prioritized taking voltage conversion into consideration.

b) Have these "savings in customer's power and power related billings" attributable to past conversion projects been separately identified in Welland Hydro's O&M cost accounts?

Response:

Savings to customer's power and power related billings are reflected in customer bill impacts sheet through the reduced loss factor.

2-Staff-19
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.1 Distribution System Plan Overview, Page 13

System Service
"System Service expenditures account for a small portion of the overall allocation of capital investment. The amount invested in this category in 2017 is largely composed of the replacement of current SCADA software and related communication equipment. SCADA investments are required to maintain system efficiency, reliability, and support in responding to certain power disruption events."

Has Welland Hydro achieved O&M cost savings by implementing automated or remote sectionalizing capabilities? Please provide details.

Response:

SCADA software and communication systems do not have a significant effect on OM&A costs. SCADA systems are used during outage events to identify outage causes and reduce outage duration through the use of remote switching.

2-Staff-20
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.1a Key Elements of the DSP, Page 14

<u>System Service</u>
"System Service investments include new assets or upgrades to systems, impacting system reliability. These projects are driven by required upgrades to support systems including Supervisory Control and Data Acquisition ("SCADA"). Additional projects include systems that support SCADA. The communication system upgrades, scheduled for the Test Year, will provide continued support to the SCADA system and drive cost efficiency. Future projects include protection and control upgrades at Municipal Substations."

a) Does Welland Hydro minimize investments in substations that are scheduled for elimination due to voltage upgrade projects?

<u>Response:</u>

Welland Hydro minimizes investments in substations that are scheduled for replacement or removal.

i. Please identify which municipal substations (if any) are planned for elimination during the period 2017-2021 to accommodate voltage upgrades.

<u>Response:</u>

There are no planned substation removals during 2017-2021.

ii. Are substation maintenance costs reduced as a result of eliminating municipal substations?

<u>Response:</u>

Removal of a substation reduces maintenance costs at that specific site.

2-Staff-21
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.1b Sources of Cost Savings, Page 15

a) **Please identify the actual or anticipated savings associated with each of the listed items in each year over the forecast period. Please explain the methodology Welland Hydro used to derive the savings estimates.**

<u>Response:</u>

Cost savings through these programs have not been determined. Some programs will improve system analysis with the potential to increase the length of in service time. Other programs will result in efficiencies in data collection and allow staff to focus time on other programs/procedures with no additional OM&A costs.

b) **For the assets being replaced, please quantify the percentage of O&M costs expended in 2016 that were dedicated to the replaced asset, as a percentage of O&M costs expended upon that asset class in 2016.**

<u>Response:</u>

Welland Hydro's internal reporting system does not track O&M costs at the level of detail to provide cost to individual assets being replaced.

2-Staff-22
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.1f Aspects Contingent on the Outcome of Ongoing Activities, Page 18

Welland Hydro notes that "There are no known activities determined by Regional Planning process to be completed in the Test Year or forecast period and WHESC has no Long Term Load Transfer customers to transfer to adjacent utilities to meet an OEB directive."

a) Has Welland Hydro actively sought input from the Municipal or Regional governments regarding their plans for roadway alterations?

Response:

Welland Hydro meets with Municipal and Regional governments quarterly through the Public Utility Coordinating Committee. Preliminary long term plans from 3 to 5 years are shared during these meetings. Project commitment and requests for Utility Line relocations typically happen less than 12 months prior to the requested relocation date.

b) What proportion of Welland Hydro's annual System Access expenditures are typically driven by roadway moves?

Response:

Expenditures for roadway moves have not been a material portion of total capital spending in the past. There are no major road widening projects confirmed at this time for the 2017-2021 period.

c) Would Welland Hydro be better able to optimize renewal expenditures by coordinating those investments with planned roadway moves?

Response:

Pole line relocations due to road reconstruction are infrequent in Welland's service territory. Welland Hydro would consider moving up a capital expenditure to correlate with a road widening project it if made sense to do so.

2-Staff-23
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.2a.1 Customer Consultations, Page 20

City of Welland Corporate Calls for Commercial Customers
"WHESC is part of the City of Welland team which meets with individual commercial customers (12-16) once each year from 2014 to 2016. These meetings were initiated by the office of the Welland Economic Development Commission and also include the Chamber of Commerce. Customers identified issues with respect to momentary outages, power equality, e-billing, global adjustment classes, electricity usage, and CDM. All of the concerns were addressed in follow-up meetings with customers. These meetings provide an opportunity for customers to share their future plans such as expansion and for WHESC to include in Distribution System Planning if required. An example of actions taken by WHESC as a result of these meetings was the early construction of the Humberstone/Townline tunnel distribution feeder in 2015 to support economic development."

a) Were the identified concerns addressed by providing explanations, or by initiating capital or operating investments related to this filing (other than the power quality complaint tracking metric identified in this section)?

Response:

There were no expressed concerns that resulted in any one specific project been added to the capital plan during the 2017-2021 period.

b) If none of the above, how were they addressed? Please provide details.

Response:

The last project that addressed reliability concerns from these meetings was the Humberstone/Townline project that was completed in 2015.

2-Staff-24
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3a.7 DSP Implementation Progress, Page 30

Actual vs. Planned Annual Spend
The intent of this metric is to measure Welland Hydro's overall planning quality with respect to its overall budget. Welland Hydro targets +/- 10% spending each year relative to the total budgeted amount.

a) Would this target be achieved if the overall planned amount is spent, even if not all planned projects are executed or if individual projects run significantly over budget?

Response:

Yes

b) Does Welland Hydro track its ratios of actual vs. planned expenditures on an individual project basis?

Response:

Actual vs Planned expenditures are tracked and analyzed for all material projects.

c) Would this provide a more meaningful measure of project efficiency?

Response:

Both measures are important in the evaluation of capital expenditures. This would include evaluation of the estimating process and whether or not changes are needed to capital expenditure plans in future years.

2-Staff-25
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3a.8 Cost Control, Page 30

Total Cost per Customer
Total cost per customer is calculated as the sum of capital and operating, maintenance, and administration ("OM&A") costs divided by the total number of customers. Welland Hydro targets a 2.5% yearly increase in this measure.

Please explain why this target is set higher than expected CPI.

Response:

As per the response to 1-SEC-9(d) expected total cost from the PEG model reflect costs such as increased OEB assessment and locate costs, public policy environment obligations such as increased customer engagement, and succession planning costs. Please note that both the original and revised PEG models forecast an improvement in actual to predicted total costs resulting in an increased efficiency performance in the 2017 compared to 2015 Actual.

2-Staff-25
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3a.8 Cost Control, Page 30

<u>Total Cost per km of Line</u>
"This measure divides the total cost (sum of capital and OM&A) by the total primary circuit kilometers maintained WHESC. WHESC targets a 2.5% yearly increase in this measure."

a) Please explain why this measure is higher than CPI.

<u>Response:</u>

See response to Total Cost per customer above.

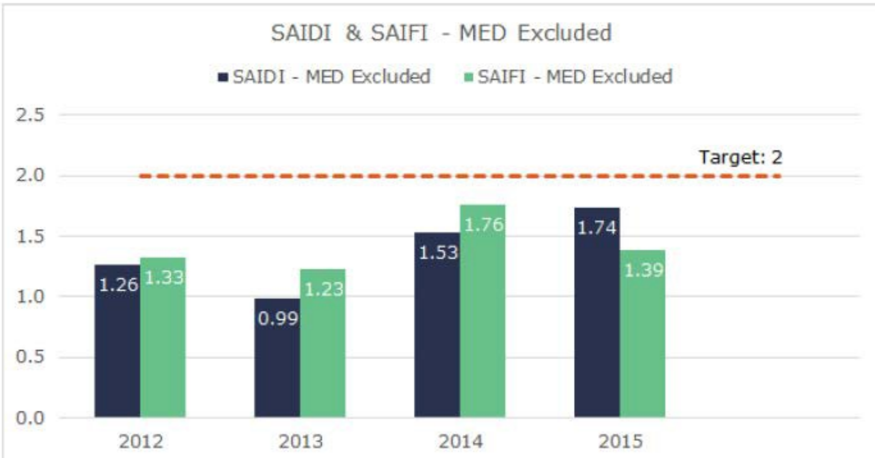
b) Should not Welland Hydro's OM&A efficiency improve as its systems are modernized?

<u>Response:</u>

Welland Hydro has submitted a forecasted PEG model which shows its overall efficiency increasing for the 2017 Test Year. Modernization of the electrical grid does not necessarily reduce OM&A costs and does not impact that rate at which assets age.

2-Staff-26
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3b.6 System Reliability, Page 40

Figure 5-12: Historical SAIDI and SAIFI performance – MED excluded



a) Why are SAIDI and SAIFI increasing after excluding major event days?

<u>Response:</u>

Currently, major events are related to weather related incidents (wind, snow, freezing rain). The equipment related events are more sporadic and are based on a number of factors including extreme heat/cold and equipment age. In 2014 Welland Hydro had one incident which it classified as equipment failure but was most likely caused by high winds. Removal of this event results in revised 2014 SAIFI at 1.16 and SAIDI at 0.98. The increase in 2015 was related to one insulator failure on a multi-circuit structure as previously noted (Staff 2-27). For 2016 actual SAIDI is 0.61 and actual SAIFI 0.70 as no major weather events occurred. Welland Hydro believes that additional discussion is required on the reporting of major events.

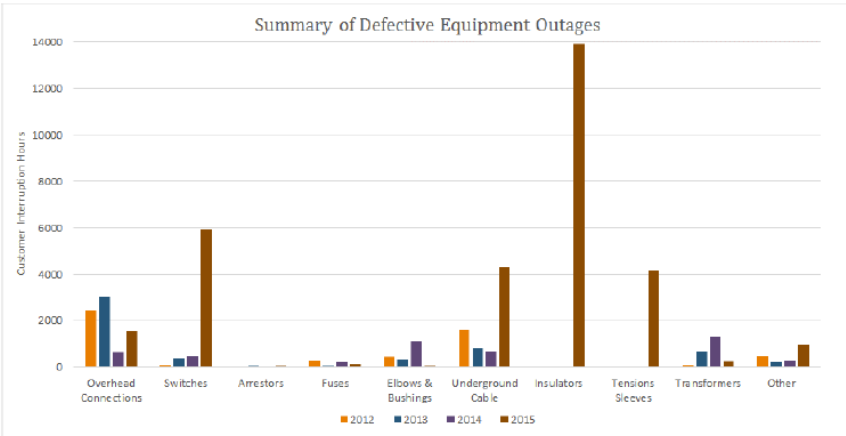
b) Should Welland Hydro be targeting ongoing improvement in these metrics after excluding MED's and Loss of Supply, since that portion of the metric is more subject to <u>Welland Hydro's direct control?</u>

<u>Response:</u>

Welland Hydro's intention is always to make its distribution system as reliable as possible while maintaining a balanced approach to capital spending. Additional discussion is needed on the classification of major events before any new targets are set.

2-Staff-27
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3b.6 System Reliability, Page 43

Figure 5-18: Summary of defective equipment outages



a) Explain the reasons behind the exceptionally high impact of insulator failures in 2015.

Response:

One insulator failure on a multi circuit pole resulted in 12,600 customer hours of interruption time in 2015.

b) What action is Welland Hydro taking to avoid similar outcomes in futureyears?

Response:

Welland Hydro replaced insulators of a similar type on the circuit affected by the insulator failure.

2-Staff-28
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3b.8 Cost Control, Page 44

<u>Total Cost per Customer</u>
Results for 2015 at $493 per customer represents a 2.1% increase over 2014 results, below the 2.5% target. These results can be impacted by one off costs such as emergency repairs and regulatory costs on a year by year basis. A comparison of 2015 cost per customer to 2012 results, shows a 2.3% increase over three years, corresponding to a 0.8% increase per year.

Figure 5-19: Total cost per customer over the historical period

How do these results map into the bill increases shown on Page 36 under 5.2.3b.3 Customer Bill Impacts?

<u>Response:</u>

Bill Impacts and the resultant percentage increases as shown on Page 36 under 5.2.3b.3 is made up of many different variables. The Total Cost per Customer shown in the above Table are from the PEG report and include almost all of the OM&A, capital expenditures, the OEB's deemed rates of return, and the PEG method of calculating depreciation. This would not reflect changes in OM&A in 2016 and 2017, changes in volumes, loss of a large use account, increased PILS rate from 19.5% to 26.0%, changes in rates of returns and working capital allowance and the impacts of the 2015-2021 CDM program.

2-Staff-29
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3b.9 CDM Program Achievement, Page 45

"Whole Home Residential and small Business Lighting Programs will be launched by the IESO to enhance savings in 2016 and 2017. Furthermore, WHESC has a large streetlight conversion project that began in 2015 and is scheduled for completion in 2016 and completion of this project will have a significant impact on the savings achieved in 2016."

a) What are the capital costs of implementing this program?

<u>Response:</u>

The projects above are not initiated or paid for by Welland Hydro. Welland Hydro's CDM team works with customers and provides energy savings incentives through CDM funding.

b) Have those costs been separately identified in Welland Hydro's 2015 & 2016 capital expenditures tables?

<u>Response:</u>

As per the response to (a) these are not Welland Hydro related capital costs.

c) Have the resulting O&M savings been separately identified in the Test Year O&M costs?

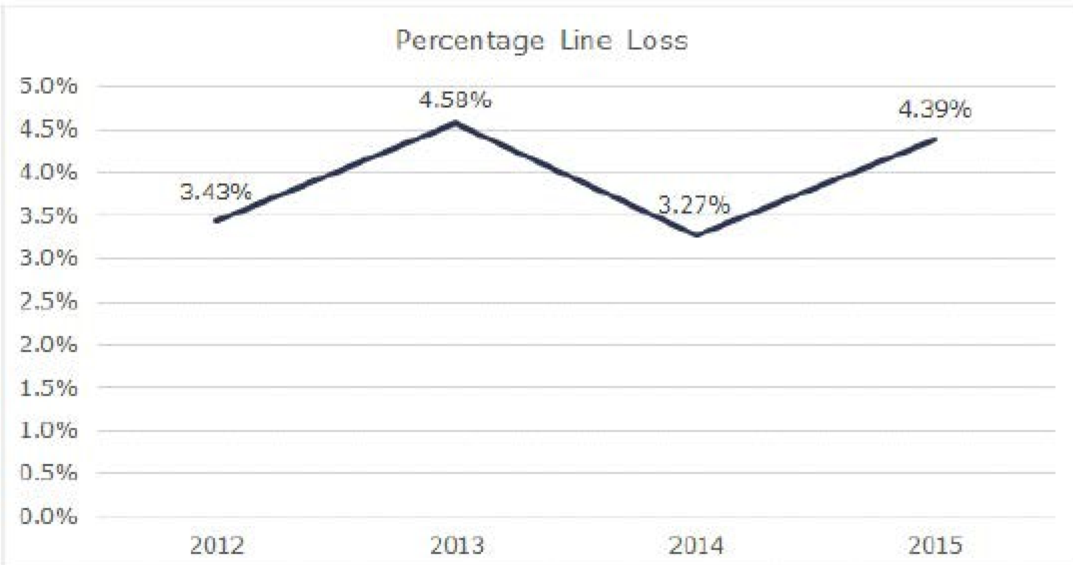
<u>Response:</u>

The costs related to CDM operating costs and incentives given to customers are not included in Welland Hydro's OM&A costs.

2-Staff-30
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.2.3c.11 Distribution Losses, Page 47

As shown in Figure 5-24, the percentage line loss fluctuates between years due to factors outside of Welland Hydro's control, such as ambient temperature. The percentage line loss was 4.39% in 2015, which is higher than 2014, but lower than the previous three-year high of 4.58%.

Figure 5-24: Historical percentage line loss



a) **Inter-annual line losses appear to be very volatile. Is this variability caused solely by differences in ambient temperatures?**

__Response:__

The variations in line losses are more related to estimating unbilled revenue (kWhs) at year end which are used in the calculation of line losses. These entries reverse in the following year and tend to balance out over time. It should be noted that the five year average line losses calculated in Exhibit 8 is almost identical to the 2015 actual. The preliminary loss factor for 2016 is estimated to be in line with 2015 actuals.

i. **If yes, please explain the mechanisms that link ambient temperatures to such volatile loss results.**

__Response:__

Not applicable.

ii. **If no, please identify the other factors that impact annual losses.**

Response:

As per the response to (a) above Welland Hydro believes the fluctuations are more related to estimating of unbilled kWhs are year-end which are included in the calculation of billed kWhs for the year.

b) Given Welland Hydro's ongoing capital investments in efficiency initiatives such as voltage conversions, why are line losses not generally trending downward over this period? Please provide details.

Response:

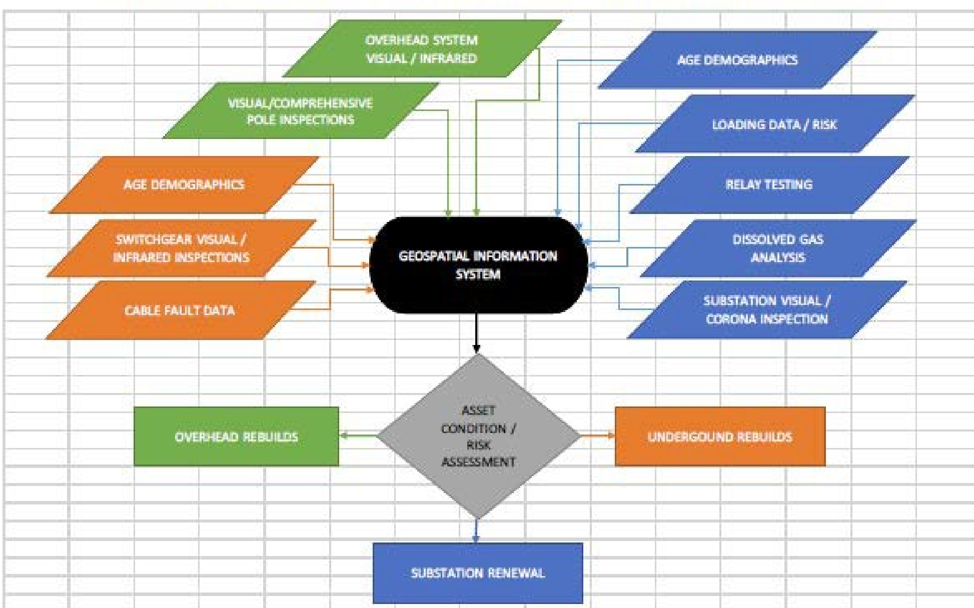
The proposed line loss factor in 2017 of 1.0476 is lower than the 2013 line loss factor of 1.0532.

2-Staff-31
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.1b Asset Management Process, Page 54

Welland Hydro does not have a formal Asset Condition Assessment process at this time. Welland Hydro plans to incorporate a USF developed program and standards when available. The results of the system inspections and assessments have been combined with both historical performance and age assessments to provide the tools to make prudent decisions on prioritization for the replacement of assets. Both data analytics and graphical analytics are tools that have been utilized to demonstrate a clear and consistent approach to assessing and scheduling for the replacement of assets.

Welland Hydro's asset management process, including inputs and outputs used to identify and select investments has been illustrated in the flowchart in Figure 5-27 and is described in further detail below. For information on project prioritization and pacing, see Section 5.4.2c – Project Prioritization.

Figure 5-27: Inputs/outputs of the asset management process used to identify and select projects



a) **Please provide examples of Welland Hydro's use of both the data analytics and graphical analytics tools referenced in this excerpt, and provide links to planned Test Year capital expenditures.**

Response:

Data analytics (reports) assist in assessing and ranking asset replacement priority. Graphical representation (mapping and color coding of overall asset condition) assist not only in confirming the data, but also provides insight as to the overall condition in areas surrounding the assets being ranked as high priority in the reports.

For example, data analytics were used to determine the age of assets in the area of the Church Street/Niagara Street overhead rebuild included in both the 2016 Bridge Year and 2017 Test Year. Based on this information graphical analytics were used to confirm the data and determine the boundaries and scope for the project.

b) When does Welland Hydro plan to implement a formal Asset Management Process?

Response:

A formal process will be implemented prior to the next Cost of Service Rate Application.

c) Please explain in detail the activities and decisions that take place in the grey diamond entitled "Asset Condition/Risk Assessment" in Figure 5-27?

Response:

All information collected in the GIS system is analyzed when completing the risk assessment. The overhead and underground assessment includes scoring/weighting of certain criteria to prioritize projects. Other assets at higher risk, such as substations follow a less formal process, focusing more on asset age to determine replacement timing.

2-Staff-32
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.1b Asset Management Process, Page 55

<u>Municipal Substations</u>
Substations are scheduled to be replaced based on age demographics, performance data, annual test results, and criticality. More specifically, the following data are analyzed and used in the asset replacement decision making process:"

a) Does Welland Hydro ever replace municipal substation transformers solely based upon demographics?

<u>Response:</u>

Age is used in assessing the replacement of substation transformers but is not the sole criteria. Testing such as oil analysis are also taken into consideration. Age in substation transformer has a higher weight in replacement analysis than distribution transformers.

b) Does Welland Hydro always validate municipal substation transformer condition before replacing?

<u>Response:</u>

Substation Transformers are inspected monthly and tested annually. The results of the testing and age are taken into consideration before replacing the transformers.

2-Staff-33
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.1b Asset Management Process, Page 56

"Poles are replaced during overhead rebuilds, as well as WHESC's pole replacement program. Although the number of poles replaced per year depends on the capital program being executed and the results of the pole assessments, WHESC tries to balance its approach, using a planned and paced process, to the total number of poles replaced on an annual basis."

a) Does Welland Hydro ever replace poles solely due to demographics?

Response:

Age is not the sole factor for pole replacement. Inspection and pole testing results are factored into each pole replacement.

b) Does Welland Hydro ever replace poles on specific feeders ahead of expected retirement to coordinate with complete pole replacement programs on those feeders driven by condition assessments or voltage upgrades?

Response:

In the majority of cases all the poles in an area undergoing a complete rebuild are of the same age. However, there are cases where it is more efficient to replace the odd pole with remaining useful life at the time of the rebuild as opposed to replacing it at a later date.

c) Does Welland Hydro conduct business cases to validate economics before implementing full rebuilds of feeders that still have significant numbers of good condition poles?

Response:

It would not be normal procedure to replace a pole line with a significant number of poles in good condition. In this case, individual pole replacement would take place if required. One exception to this case would be road widening projects.

2-Staff-34
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.1b Asset Management Process, Page 60

Welland Hydro notes that it "…has invested money and will continue to invest money in a prudent manner to keep the facility operational without unnecessary cost increases to its customers."

Are details of the building investments included in the capital plans filed as part of this application?

Response:

Capital projects related to buildings are detailed in Chapter 2 Appendices 2-AA by year. A detailed project sheet related to the repaving of the service center parking lot in 2017 is included in Appendix 5-D Project Justification Forms in the Distribution System Plan.

2-Staff-35
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.1b Asset Management Process, Page 60

"SCADA communication continues to be an operating cost consideration. Currently, WHESC uses a combination phone lines, wireless radio systems and cellular devices to communicate to in field devices. Projects are underway to test additional wireless systems and data concentrators with the intention of reducing the amount of communication lines and systems."

What are the annual operating costs associated with the communication systems referenced in this paragraph?

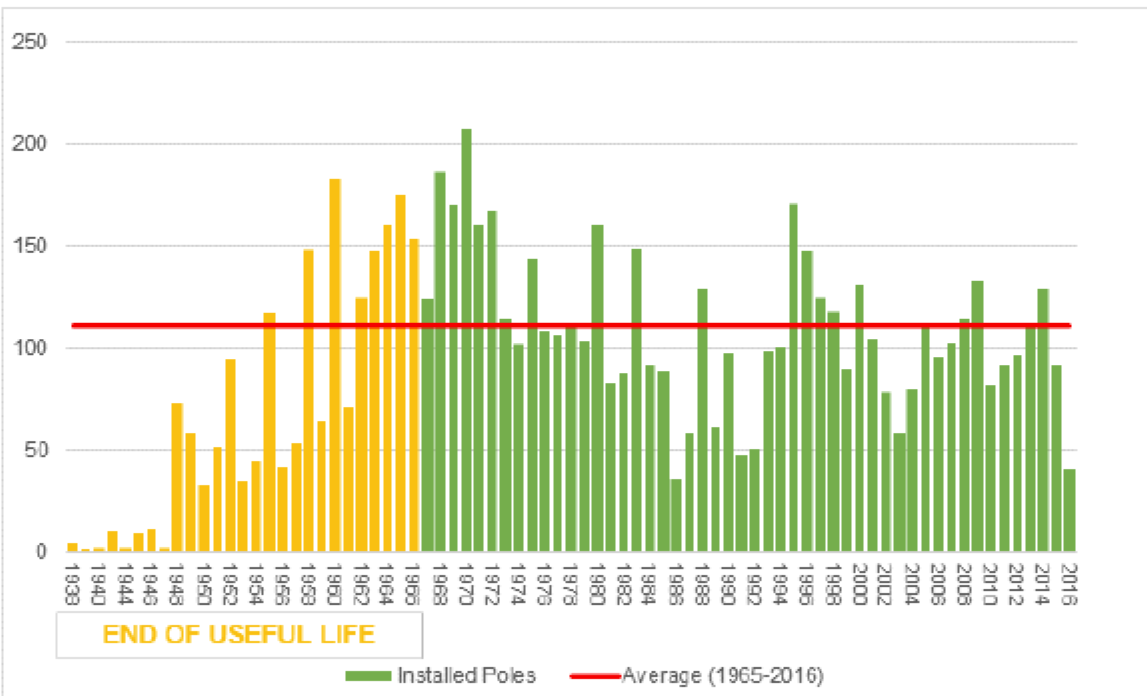
Response:

Approximately $55,000 annually.

2-Staff-36
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.2c.2 Poles, Page 66

Welland Hydro owns approximately 8,000 wood poles. Poles are fully depreciated after 50 years but can last many years longer depending on many factors including material, treatment and environmental conditions. Figure 5-32 below illustrates the number of poles currently in service, the quantity for each year, and the average age of poles currently in service.

Figure 5-32: In-service dates of wood poles



a) From the graph above, it seems as though the average age is not indicated. What is the average age of the wood poles currently in service?

<u>Response:</u>

Average age of poles currently in service is 40 Years.

b) Are all wood poles in Welland Hydro's system of the same species?

<u>Response:</u>

The two main species are pine and cedar.

i. **If not, does Welland Hydro apply the same 50-year useful life assumption for all species?**

Response:

Welland Hydro applies the same 50-year useful life to all poles in service.

c) **Considering the total count of poles identified as being significantly beyond "end of useful life", is that categorization appropriate for all the poles soidentified?**

Response:

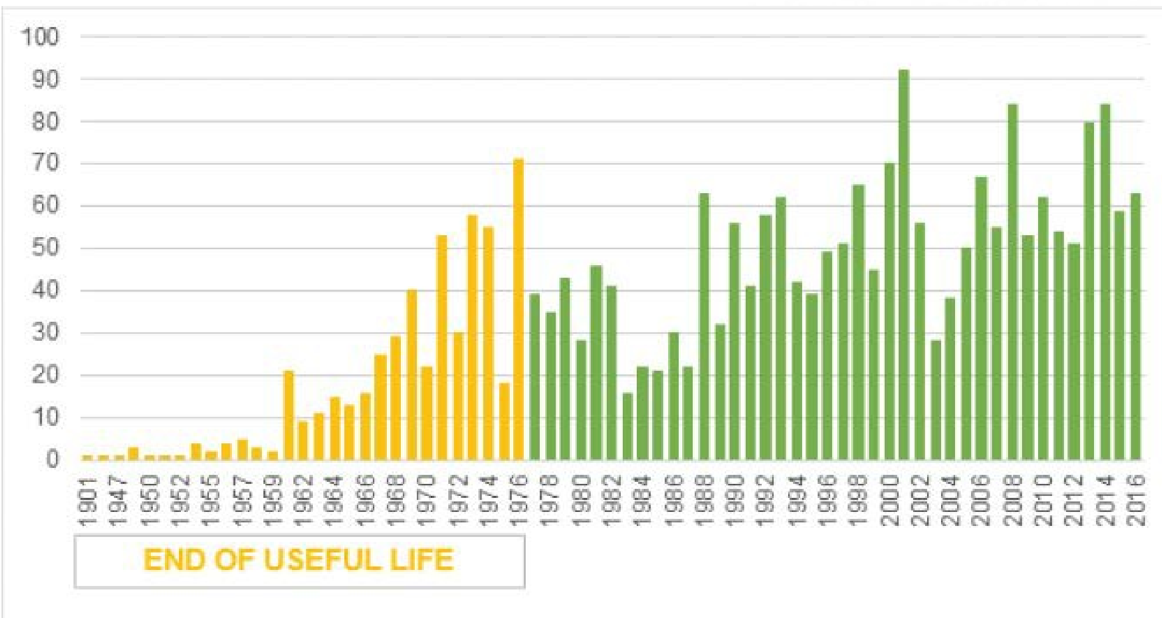
For the most part yes although it is not the main factor for replacement. Testing may indicate poles in the green section of the chart need replacement.

2-Staff-37
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.2c.3 Distribution Transformers, Page 67

Welland Hydro owns approximately 2,300 distribution transformers ranging in size from 5 to 1500 kVA. Transformers are fully depreciated after 40 years but are replaced immediately on failure or typically if they have any deficiencies that introduce risk.

Figure 5-33 illustrates the number of transformers in service and the quantity installed each year.

Figure 5-33: In-service dates of distribution transformers



a) What sorts of "deficiencies introduce risk", as referenced above?

Response:

Other risks can include items such as equipment hot spots, broken insulators, potential for oil leaks, etc.

i. How is the risk quantified?

Response:

The risk is quantified base on the expert opinion of qualified staff.

ii. **Who ultimately decides if the risk due to a specific deficiency is high enough to justify transformer replacement, and what criteria are applied in making that decision?**

Response:

Engineering makes the final decision based on information provided by other departments and inspection data.

b) Considering the total count of distribution transformers identified as being significantly beyond "end of useful life", is that categorization appropriate for all the transformers so identified?

Response:

For the most part yes although it is not the main factor for replacement. Testing may indicate transformers in the green section of the chart need replacement.

2-Staff-38
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.3b Asset Life Cycle Risk Management, Page 74

"The assessment of risk begins with the inspection of assets. Assets are inspected and inspection data is loaded into the GIS. Inspection data, data from other analysis and asset performance data are used to estimate the probability of failure. The determination of the probability is determined solely on the use of historical data and experience (i.e. at this time, there is no formal process to derive a health index and associate a probability of failure)."

a) Please confirm that the described process is primarily based upon the exercise of judgment by experienced personnel.

Response:

Where relevant inspection and performance data is available, projects are scored to determine asset replacement timing. In the absence of relevant data, judgement may be exercised through expert opinion.

b) Does the existing process review past decisions to confirm that the decisions were appropriate decisions, which then informs and improves the assessment process?

Response:

The decision to replace is not reviewed but a review is conducted if actual costs exceed budget to facilitate improvements in future cost forecasting of capital projects.

2-Staff-39
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.3b Asset Life Cycle Risk Management, Page 75

<u>Overhead Systems</u>
As introduced in Section 5.3.1b – Asset Management Process, Welland Hydro selects and prioritizes investments into overhead systems based on the system voltage level, reliability (configuration and worker access), voltage conversion potential, connection of new customers, pole condition, and customer criticality.

Table 5-18 Selection and prioritization of overhead rebuild projects based on risk analyses

Project Number	Location	Job Description	Voltage RRFE	Score 1-5	Reliability Op. Eff. Loop	Score 0-5	Efficiency Fin. Perf. Converted	Score 0-5	New Customer Cust. Focus Connection	Score 0-5	Reliability Op. Eff. Worker Access	Score 0-5	Safety, Reliab. Enviroment Public Policy Pole Condition	Score 0-10	Customers C/I/R Cust. Focus Criticality	Score 0-5	Total Points	Budget	Year
1	Niagara/Church/Aqueduct	27.6kV Extension	27.6kV & 4.16kV	5	Yes	5	1000	5	No	0	Good	0	Poor	5	High	4	24	$750,000.00	2016/ 2017
2	Wellington Street	4.16kV Line Rebuild/27.6kV Extension	27.6kV & 4.16kV	5	Yes	5	500	3	School	5	Good	0	Fair	3	Medium	3	24	$338,000.00	2016/ 2017
3	Riverview Drive	2.4kV Rebuild & Conversion	2.4kV	4	No	0	400	3	No	0	Poor Access	3	Decayed	10	Low	0	20	$150,000.00	2017
4	Bradley Ave/Robert Street	27.6kV Conversion	27.6kV & 4.16kV	5	No	0	150	1	No	0	Feed to Robert	5	Poor	9	Low	0	20	$49,485.00	2017
5	Ross & Kennedy	16kV Extension	16kV	3	No	1	150	1	No	0	Good	0	Poor	10	Low	1	16	$250,000.00	2017/ 2018
6	Ontario Road - Corridor to Wellington	27.6kV & 4.16kV Rebuild	27.6kV & 4.16 kV	5	Existing	3	215	1	No	0	Good	0	Fair/Poor	3	High	4	16	$300,000.00	2018
7	Lincoln Street - Coventry to Scholfield	27.6kV Rebuild and Tower Removals	27.6kV & 4.16 kV	5	No	5	475	3	No	0	Good	0	Fair	3	Medium	3	19	$440,000.00	2019
8	Duncan - Hagar to East Main	27.6kV Extension	27.6kV & 4.16kV	5	No	2	800	4	No	0	Good	0	Poor	5	Low	2	18	$620,000.00	2019/ 2020
9	Denistoun Ave - Hooker to River	27.6kV Rebuild	27.6kV & 4.16kV	5	Existing	3	600	3	No	0	Good	0	Fair/Poor	3	Low	1	15	$250,000.00	2020
10	Myrtle Avenue	4.16kV Line Rebuild/27.6kV Extension	27.6kV & 4.16kV	5	Yes	5	150	1	No	0	Good	0	Fair/Poor	5	Low	1	17	$165,000.00	2020
11	Dorothy Street - Riverside to Ross	16kV Conversion	16kV	3	No	0	150	1	No	0	Fair - Trees	3	Poor	8	Low	0	15	$100,000.00	2020
12	Clare Avenue - Fitch to Erin	4.16kV Line Rebuild/27.6kV Extension	27.6kV & 4.16kV	5	Future	3	237	1	No	0	Good	0	Fair	3	Low	1	13	$100,000.00	2020
13	Hellems Ave/Park Street	27.6kV Overhead Extension	27.6kV & 4.16kV	5	Yes	3	180	1	No	0	Fair - Trees	3	Fair/Poor	5	Low	0	17	$310,000.00	2021
14	King Street - Lincoln to Regent	27.6kV Overhead Extension	27.6kV & 4.16kV	5	Duplicate	3	750	4	No	0	Good	0	Fair/Poor	3	Medium	3	18	$300,000.00	2021
15	Classic/Lewis	2.4kV Rebuild/Conversion	16kV	4	No	0	750	4	No	0	Good	0	Poor	10	Low	0	18	$350,000.00	2021
16	Rusholme Road - Ridge Road to CNR Tracks	27.6kV Rebuild	27.6kV	5	No	0	0	0	No	0	Good	0	Fair/Poor	3	High	4	12	$150,000.00	2021

a) Can Welland Hydro provide the set of projects that did not make the list?

<u>Response:</u>

There is a 10-year outlook for potential projects, however, only projects in the 5-year window were scored to determine replacement timing.

b) Please explain the column headings used in this table and show the parameters and calculations used to assign the numeric scores for each column.

<u>Response:</u>

Voltage - The number of circuits and voltage of each circuit on the pole. Quantity of circuits and higher voltage feeders result in higher risk due to failure.

Reliability - (Loop Feed) – An evaluation of the potential benefits to system reliability. If the project will establish a loop feed for backup, it receives additional points.

Efficiency – If the project includes voltage conversion, the amount of load converted is assessed.

New Customer – If the project provides new customer connections or the potential for additional customer connections.

Reliability (Worker Access) – If the project will improve worker access to the assets, future restoration times will be impacted.

Safety & Environment – An assessment of the perceived benefits to the public and environment.

Criticality – An assessment of the customers connected to the assets and the result of asset failure to these customers

c) How long has Welland Hydro used this prioritization system? How often does Welland Hydro review the process, and score weightings?

Response:

This is a new prioritization system. The process and weightings will be reviewed during the development of a formalized asset assessment plan.

d) Does the existing process review past decisions to confirm that the decisions were appropriate decisions, and which then informs and improves the assessment process presented in the table above?

Response:

No - See Response to staff 2-38.

2-Staff-40

Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.3.3b Asset Life Cycle Risk Management, Page 76

Table 5-19: Selection and prioritization of underground rebuild projects based on risk analyses

Project #	Subdivision	Street	Install Date	Cable Faults	Circuit	Length (m)	KVA	Convert/ Re-Build	Cable Age Points	Cable Faults Points	R-B/C Points	Total Points	Budget	Year
1	Seaway Park Subdivision	Robert St	1975	2	8F1	165.67	150.0	Convert	1	6	6	13	$150,000	2017
1	Seaway Park Subdivision	Robert St	1975	0	8F1	163.12	150.0	Convert	1	0	6	7		
1	Seaway Park Subdivision	Robert St	1975	0	8F1	175.62	150.0	Convert	1	0	6	7		
1	Seaway Park Subdivision	Robert St	1975	0	8F1	186.24	150.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	2	10F3	65.65	525.0	Convert	1	6	6	13	$490,000	2016 - 2017
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	1	10F3	74.75	525.0	Convert	1	3	6	10		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	36.19	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	57.07	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	64.47	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	69.05	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	70.74	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	70.79	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	70.83	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	71.48	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	74.79	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silven Dr	1976	0	10F3	99.05	525.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Cummington Pl	1976	0	10F3	45.81	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Cummington Pl	1976	1	10F3	130.2	187.5	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	Leaside Dr/Meadowvale	1976	0	10F3	89.79	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside	1976	0	10F3	178.47	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Meadowvale Pl	1976	0	10F3	36.69	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	0	10F3	90.82	75.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	0	10F3	100.55	75.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	0	10F3	167.53	75.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	1	9F1	148.48	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	Leaside Dr/McCrae	1976	1	9F1	232.34	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	McCrae Dr/Newleaf Cres	1976	1	9F1	169.66	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	1	9F1	41.63	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	McCrae Dr	1976	0	9F1	55.03	250.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	0	9F1	60.38	250.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	0	9F1	79.09	250.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	0	9F1	133.55	250.0	Convert	1	0	6	7		
6	Glen Park Estates - EXT 1	Mauraen Ave	1974	0	7F1	101.26	125.0	Re-Build	3	6	0	9	$125,000	2017
6	Glen Park Estates - EXT 1	Mauraen Ave	1974	0	7F1	112.94	125.0	Re-Build	3	6	0	9		
6	Glen Park Estates - EXT 1	Mauraen Ave	1974	0	7F1	183.23	125.0	Re-Build	3	6	0	9		
6	Glen Park Estates - EXT 1	Mauraen Ave	1971	1	7F1	183.23	125.0	Re-Build	3	6	0	9		

Please explain the column headings used in this table and show the parameters and calculations used to assign the numeric scores for each column.

<u>Response:</u>

Cable Age – Up to 4 points available based on age.

Cable Faults – 3 points per fault on each segment of cable within the project.

Rebuild/Convert – Projects that include voltage conversion receive an additional 6 points.

2-Staff-41
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.4.1c.2 System Renewal, Page 80

"The most current cable replacement ranking is organized first by the cables in service from 1969 to 1976. Cables are organized by subdivision name and grouped with other stages of subdivisions that makes the most sense for achieving cost savings during asset replacement."

How are the described cost savings measured? Please provide examples.

Response:

When an area is being rebuilt, it is most cost effective to include all adjoining or interconnected streets within the project area for assets of the same approximate age. There is no formal process to determine cost savings.

2-Staff-42
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.4.1g Expected System Development over the Planning Horizon, Page 83

Smart Grid Development
"Welland Hydro will continue to invest in smart meters over the forecast period."

a) Why is Welland Hydro going to continue to invest in smart meters?

Response:

Smart Meter investments provide meters for new customer connections, replacement of failed meters, and the implementation of the Measurement Canadas Seal Extension Program.

i. What is the ultimate goal of these investments?

Response:

To maintain the operation of the metering network and properly bill customers.

b) Do all smart meter technologies provide identical functionality?

Response:

All smart metering networks provide the same basic functionality requirements.

i. If not, how did Welland Hydro determine the appropriate meter functionality to implement?

Response:

Welland Hydro, along with 9 other LDC's, evaluated and selected the same metering network equipment and services as a group.

ii. Are the smart meters that will be installed in the forecast period functionally identical to the smart meters already installed in Welland Hydro's system?

Response:

The basic functionality has not changed.

2-Staff-43
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.4.2b Non-Distribution System Alternatives, Page 87

"WHESC does not have a formal process of determining the effects of CDM and REG projects on the load forecast. The IESO's current Conservation First Framework focuses on energy conservation and does not consider the particulars of peak shaving, while REG is intermittent and cannot be relied on to trim peak demand without the use of energy storage. Since system capacity and operational constraints are usually determined by peak conditions, CDM and REG in their present regulatory states would have little effect. WHESC makes assumptions, based on historical information, on the potential for these programs to mitigate future costs related to increased capacity requirements. A more formal process will be considered in the future during the next wave of Regional Planning. However, a formal process at this time is not seen as necessary, due to slow growth and available Transformer Station capacity."

Has Welland Hydro considered the potential impact of higher levels of penetration of electric vehicles on its distribution system over the forecast period?

<u>Response:</u>

Current system demand is well below the capacity of the Distribution System and associated connected transmission assets. There is no expectation for impact on the distribution system during the forecast period.

2-Staff-44
Ref: Appendix 2-A – Distribution System Plan 2017 Test Year – Section 5.4.2d.3 Random Telephone Survey, Page 94

"**System Challenges and Priorities**

- **The majority (54%) of residential customers feel that Welland Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability.**

- **The run-to-failure approach is not supported by residential customers. Two-thirds (65%) of residential customers would prefer to replace equipment before it breaks down vs. waiting for its full value (26%).**"

a) **Please describe the apparent misalignment in customer expectations demonstrated in the excerpted reference: 2/3 of residential customers prefer to replace equipment before it breaks down, yet only 54% feel that Welland Hydro should invest what it take to replace the system's aging infrastructure?**

Response:

WHESC does not interpret a misalignment based on the results referenced above. In both cases a majority of customers expect WHESC to pursue a pro-active infrastructure replacement approach.

b) **Did Welland Hydro discuss the apparent contradiction in these answers with customers?**

Response:

1. WHESC does not interpret these results as an apparent contradiction; and

2. To date, no specific attempt to discuss survey results with customers has been made.

c) **Did Welland Hydro explain the incremental costs and rate impacts of preventative asset replacements?**

Response:

The telephone surveys conducted by INNOVATIVE included an explanation of incremental costs and preventative asset replacements. The question was asked first if residential customers believe that WHESC should replace aging infrastructure and 54% agreed with this statement, but when asked if WHESC should run to failure more customers did not support the run to failure option as customers may want to replace equipment before they fail, to prevent outages. Customers may want to ensure that WHESC properly analyzes the need for replacement before infrastructure is replaced, as WHESC re-assured customer during the consultation group sessions and large customer information sessions. Another question that may also address this issue was asked of these respondents as to why they were willing to accept the rate increase and 83% responded favourably for the following reasons: maintenance/infrastructure spending is necessary for reliable service (44%) or the increase was not too much (39%).

2-Staff-45
Regulatory Charges Ref: Ex.2, Page 35

At the above reference, Welland Hydro lists the 2017 regulatory charges as follows:

- **Wholesale Market Service Rate (WMSR): $0.36/kWh**
- **Rural Rate Protection Charge (RRRP): $0.13/kWh**
- **Ontario Electricity Support Program Charge (OESP): $0.11/kWh**

a) Please confirm that the rates listed above are a typographical error and read: $0.0036/kWh, $0.0013/kWh and $0.0011/kWh, respectively.

<u>Response:</u>

Welland Hydro can confirm that a typographical error was made on Page 35 of Exhibit 2 under Regulatory Charges and the correct rates should read as outlined above. The proper rates were used in the calculation of the cost of power as can be seen in Table 2-23 on page 37 of Exhibit 2.

OEB staff notes that the OEB has determined[1] that the RRRP charge for 2017 shall be $0.0021 per kWh. The WMS rate used by rate-regulated distributors to bill their Class A customers shall continue to be $0.0032 per kWh. For Class B customers, a CBR component of $0.0004 per kWh is added to the WMS rate for a total of $0.0036 per kWh. The OESP on-bill rate assistance credits to low income electricity customers remain unchanged; in addition, the OESP charge will remain the same at $0.0011 per kWh[2].

b) As part of its response to interrogatory 6-Staff-58, please update Welland Hydro's regulatory charges and proposed Tariff of Rates and Charges to include the following:

Wholesale Market Service Rate - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) – Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011

If unable to separate the WMSR and CBR riders due to limitations with the model, please ensure that the total of $0.0036/kWh is entered under one heading for bill impact purposes.

<u>Response:</u>

Welland Hydro has updated its Tariff of Rates and Charges filed in response to interrogatories to reflect the changes requested in (b) above. Welland Hydro did not adjust the bill impact model to reflect the changes but has ensured the total of $0.0036/kWh was entered under one heading for bill impact purposes.

SEC – Exhibit 2

2.0-SEC-13

[Ex. 2, p. 5] With respect to Table 2-1:

a) Please confirm that the Applicant is proposing a Test Year Gross Fixed Assets that is 14.92% higher than 2013 Actual GFA, a CAGR of 3.54% per year.

Response:

Confirmed

b) Please confirm that the Applicant is proposing a Test Year Net Book Value of PP&E that is 15.70% higher than 2013 Actual NBV, a CAGR of 3.71% per year.

Response:

Confirmed

c) Please advise whether the increase in GFA and the increase in NBV for that four-year period are higher or lower than the increases in those items for the previous four-year period (2009 to 2013), and the four-year period prior to that (2005-2009).

Response:

2005	Average Gross Fixed Assets	$37,128,805	
2009	Average Gross Fixed Assets	$45,351,990	22.1% over 4 years
2013	Average Gross Fixed Assets	$53,179,450	17.3% over 4 years
2005	Average Net Book Value	$18,816,875	
2009	Average Net Book Value	$20,797,415	10.5% over 4 years
2013	Average Net Book Value	$25,393,150	22.1% over 4 years

The CAGR for Average Gross Fixed Assets is 5.13% from 2005 to 2009 and 4.06% from 2009 to 2013. The CAGR for Average Net Book Value is 2.53% from 2005 to 2009 and 5.12% from 2009 to 2013.

d) Please provide the percentage increases and CAGR for both GFA and NBV for each of those prior periods, and provide a high-level explanation of any acceleration or deceleration in the pace of capital asset increases since then.

Response:

The percentage increases have been provided in the response to (c) above.

The growth in Average Gross Book value over the two four year periods requested exceeds the growth rate in Average Gross Book value from 2013 to 2017. The growth in the 2009 to 2013 has been impacted by the addition of Smart Meters of approximately $3 million dollars.

Average Net Book has also been impacted by the addition of Smart Meters. However, there is a key difference between NBV growth pre-and post the change related to useful lives (significant) and indirect overheads no longer capitalized beginning in 2012. In 2012, the decrease in the depreciation far exceeded the elimination of indirect overheads being capitalized. This will result in higher growth in NBV since the changes in accounting policies in 2012.

2.0-SEC-14

[Ex. 2, p. 26] With respect to Table 2-17:

a) Please confirm that the line after 1908 should be labelled "Subtotal Buildings and Fixtures".

Response:

Correct

b) Please confirm that the line after 1960 should be labelled "Subtotal Equipment".

Response:

Correct

c) Please advise whether the 49.66% increase in GFA of IT Assets from 2013 Actual to 2017 Forecast, a CAGR of 10.6% per year, is expected to continue for the next four-year period. Please explain your answer, either way.

Response:

Growth in GFA of IT Assets from 2013 to 2017 has increased by 49.66%.

Welland Hydro has submitted a revised capital continuity schedules for 2016 Actual and the 2017 test year. The 2017 Test Year GFA for IT Assets is now forecast at $1,216,818 versus the original estimate of $1,327,813. The new forecasted growth rate from 2013 Actual to 2017 Test year is 37.15%. The capital budget for IT Assets from 2018 to 2021 is $75,000 per year which is 6.2% per year before accounting for reductions for assets being replaced.

d) Please advise whether the 30.03% increase in GFA of Equipment from 2013 Actual to 2017 Forecast, a CAGR of 6.8% per year, is expected to continue for the next four-year period. Please explain your answer, either way.

Response:

The growth in GFA of equipment is primarily related to vehicles. The 2016 International Truck purchased in 2016 for a total value of $359,199 replaced a vehicle with a gross fixed asset value of $177,191. The Digger/Derrick purchased in 2016 for a total value of $301,937 replaced a vehicle with a gross fixed asset value of $145,007. The difference in replacement versus historical costs have contributed to the increase in GFA over the 2013 to 2017 period. The growth in GFA of equipment will be less over the next four years. The bucket truck to be purchased in 2020/21 for $370,000 replaces a vehicle with a GFA of $163,584 which will result in a change to GFA.

e) Please explain why, given the large increases in General Plant, the increase in GFA of Distribution Plant (in 2-16) from 2013 Actual to 2017 Forecast is only 9.43%, a CAGR of 2.28% per year.

Response:

In 2014, Contributions and Grants were netted against Distribution Plant upon conversion to IFRS. This had no impact on GFA or NBV. However, for comparison purposes between 2013 and 2017 both categories should be added together to get the overall GFA in Distribution Plant as per the following:

	2013 GFA	**2017 GFA**	
Distribution Plant	$50,151,783	$54,878,938	
Contribution and Grants	(3,188,642)	(614,181)	
Total	$46,963,141	$54,264,757	15.5%

The third category in Table 2-16 is General Plant which increased by 24% with the majority related to vehicles.

VECC – Exhibit 2

2.0-VECC-9
Reference: E2/pg.12 / Table 2-17

a) With respect to fixed asset continuity why is there no work in progress for 2016 or forecast for 2017 whereas all the proceeding years had amounts of work in progress?

Response:

Welland Hydro has submitted a 2016 actual fixed asset continuity which shows work in progress at the end of 2016 totaling $69,322 which is related to two projects. The first phase of the Wellington Street rebuild/conversion from East Main to Eastdale represents $48,742 of work in progress. Please note that the poles installed were actually in service at the end of 2016 with the existing circuit in place. Welland Hydro elected to keep this in work in progress until 2017 when the conversion to 27.6 will take place. The other $20,639 relates to the installation of a primary cable road crossing required for work to be conducted in 2017 but was done early to allow repaving of the road prior to the winter months.

There are no projects expected to be in work in progress in 2017.

2.0-VECC-10
Reference: E2/pg.24

a) Please provide a table showing all contributions (deferred revenue) for each year 2013 through 2017 (forecast).

Response:

The following table shows capital contribution from 2012 Actual to Revised 2017 Test Year filed in responses to interrogatories. The totals below are net costs (Gross Value of Assets Less Customer Contribution = Capital Contribution Welland Hydro).

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2016 Actual Year	2017 Test Year	2017 Test Year Revised
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Expansions (Subdivisions)								
Clare Estates 1	9,160							
Elmwood Estates	28,368							
Hunter's Pointe - Galloway	26,515							
Hunter's Pointe - Block 150	2,316							
Shipview Court	10,175							
Webber Estates		28,503						
Blue Rive Estates		16,214						
Hunter's Pointe - Masters		9,864						
Hunter's Pointe - Highlands		14,820						
Coyle Creek 2 & 3			6,800					
Pine Creek			6,919					
Clare Estates 2			1,902					
Coyle Creek 4			8,112					
Tetherwood 2			6,583					
Michael Drive				4,230				
Clare Estates 3				10,068				
Lochness North 1				10,112				
Forest Creek Subdivision						3,120		
Woodview Subdivision						12,378		
Coyle Creek 6						10,597		
Sub Total Subdivisions - Plan	**76,534**	**69,401**	**30,316**	**24,410**	**50,000**	**26,095**	**50,000**	**25,000**

b) Please provide the actual 2016 contributions.

Response:

See response to (a) above.

c) Please explain how the 2017 forecast for contributions is calculated.

Response:

The forecast for both the 2016 Bridge Year and 2017 Test Year were based on the actual four-year average from 2012 to 2015 of $50,165. The 2017 Test Year has been revised to reflect a lower subdivision capital contribution amount of approximately $25,000.

d) Please provide the 2013 capital contributions agreed upon in the last cost of service application.

Response:

The amount of contributed capital related to subdivision in the approved 2013 COS Rate Application was $50,000.

2.0-VECC-11
Reference: E2/pg.30

a) **Please explain why the 26-year-old digger/derrick truck to be replaced in 2017 was not replaced in 2014 when it became apparent that a significant investment ($9,296) would need to be made in order to keep it operating?**

Response:

In 2014 a decision was made to make capital repairs to the vehicle with the intention of using it for another 5 years. Post repair breakdowns revealed that sourcing part replacements was becoming a challenge leaving Welland Hydro exposed to the risk of being without the use of a primary vehicle used for capital projects. Welland Hydro sold the digger/derrick truck in 2016 for $5,000. The truck had a net book value of $4,648 which resulted in a gain of $352.

2.0-VECC-12
Reference: E2/pg.

a) Please update Appendix 2-AA to include 2016 actuals.

Response:

See response to Board Staff 2-14 (c) above.

b) Please explain any significant variances from the 2016 budget to actual.

Response:

Total actual capital costs for 2016 of $2,837,176 exceeded 2016 forecast of $2,631,800 by $205,376. The two (2) projects which have significant overages to forecast were as follows:

	Actual	Forecast	Overage
Overhead-Church/Niagara	$606,532	$450,000	$156,532
MS #5 HV Transformer Failure	77,684	NIL	77,684
TOTAL			$234,216

The transformer failure at MS#5 was unexpected and damage was beyond repair resulting in immediate replacement. This asset was beyond its useful (53 years old) life but inspection (oil analysis) testing did not indicate replacement was required. The overage for the Church/Niagara rebuild & conversion became larger than anticipated. Between preliminary and final design stages, additional assets were deemed necessary to accommodate side street distribution.

2.0 – VECC -13
Reference: E2/pg. 35

a) Please update the working capital allowance for the October 16, 2016 Regulated Price Plan Report (Nov.1 2016-October 31 – 2017) and the updated (October 27, 2016) Board issued cost of capital parameters (see 5-Staff-57).

<u>Response:</u>

See Response to Board Staff 2-13 above for the revised Cost of Power calculations used to determine the revised working capital.

2.0-VECC-14
Reference: E2/pg. 40 Table 2-24

a) Please update Table 2-24 to show 2016 actuals and to show the budgeted amounts for 2014 and 2015.

<u>Response:</u>

As stated in the Explanatory notes to schedule Appendix 2-AB, the Plan amounts from 2014 and 2015 are from the Asset Management plan from Welland Hydro's 2013 COS Application. These categories were not in effect at the time and as a result there is no budgeted breakdown between the categories. Below is an updated Table 2-24 which reflects 2016 Actuals.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated
Distribution System Plan Filing Requirements

First year of Forecast Period: *2017 Revised*

CATEGORY	Historical Period (previous plan[1] & actual)								
	2012			2013			2014		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%
System Access		225,766	--	135,000	85,482	-36.7%		111,353	--
System Renewal		1,233,301	--	1,334,200	1,504,700	12.8%		1,710,305	--
System Service		8,300	--	35,000	4,047	-88.4%		55,500	--
General Plant		417,631	--	472,165	517,076	9.5%		322,389	--
TOTAL EXPENDITURE	1,887,015	1,884,998	-0.1%	1,976,365	2,111,305	6.8%	2,002,500	2,199,547	9.8%
System O&M		$2,978,610	--	$3,013,809	$2,886,152	-4.2%		$2,926,724	--

CATEGORY	Historical Period (previous plan[1] & actual)						Forecast Period (planned)				
	2015			2016			2017 Revised	2018	2019	2020	2021
	Plan	Actual	Var	Plan	Actual	Var					
	$ '000		%	$ '000		%	$ '000				
System Access		94,079	--	147,000	- 9,711	-106.6%	139,501	250,000	250,000	190,000	150,000
System Renewal		1,773,585	--	1,683,000	2,092,804	24.3%	1,834,485	1,495,000	1,775,000	1,920,000	1,770,000
System Service		33,237	--	-	3,231	--	80,000	260,000	35,000	35,000	35,000
General Plant		281,463	--	801,800	750,852	-6.4%	155,000	305,000	400,000	295,000	525,000
TOTAL EXPENDITURE	2,027,500	2,182,364	7.6%	2,631,800	2,837,176	7.8%	2,208,986	2,310,000	2,460,000	2,440,000	2,480,000
System O&M		$3,154,558	--	$3,255,419	$3,276,681	0.7%	$3,392,703				

2.0-VECC-15
Reference: E2/pg.43 & Appendix 2-G DSP/pg. 110 Table 5-36

a) Please provide the actual cost and delivery date of the International bucket truck and the Digger/Derrick.

Response:

International Bucket Truck: $359,199 ($117,800 in 2015 CWIP)
Date Delivered: July 21, 2016

Digger/Derrick: $301,937
Date Delivered: November 14, 2016

b) Please explain why part of the bucket truck cost was included in 2015 CWIP.

Response:

Welland Hydro was required to provide a deposit equivalent to the cost of the cab and chassis. As a result, this item was left in 2015 CWIP.

c) Please provide Welland Vehicle replacement costs for 2012 and 2013.

Response:

There were no new vehicles purchased in 2012.

In 2013, the only vehicle purchased was a Freightliner Double Bucket Truck purchased at a total cost of $325,615.

d) Based on past experience and the description for vehicle replacements in 2021 it would appear that Welland schedules major vehicle replacements for the bridge and test year of its cost of service application time periods. Please explain why.

Response:

Welland Hydro's current vehicle replacement strategy is to keep large vehicles for approximately 15 years. The digger/derrick purchased in 2016 was originally scheduled for 2019 based on an engine rebuild in 2014. However, as stated previously parts for this 26-year-old vehicle were difficult to find as the original manufacturer is no longer in business. The single bucket truck scheduled for replacement in 2020/2021 will be 21 years and the digger derrick scheduled for 2021/2022 will be 32 years old. Welland Hydro will need to maintain its vehicle fleet to sustain the reduction in mechanics from two to one full time employees.

e) Please provide Welland's vehicle replacement policy.

<u>Response:</u>

As per section 5.4.2c of the DSP the general guideline for vehicle replacements:

Small Vehicles, Pickup Trucks and Vans – 10 to 12 years
Bucket Trucks and Diggers – 15 years
Trailers and other equipment – 20 years

2.0-VECC-16
Reference: E2/pg.47/Table 2-26A

a) Please explain why there are no forecast capital contributions with respect to the forecast 50k in subdivision plant expansion.

<u>Response:</u>

Welland Hydro has included $50,000 in related to Contributed Capital-Subdivisions in every year from 2016 to 2021 (Original Application). The forecasted contributed capital for the sale of transformers has no budget for 2016 to 2021 and is discussed below in section (b).

b) Please separate contributed capital related to subdivisions from all other contributed capital in the line entitled "Contributed Capital Sale of Transformers/Meters."

<u>Response:</u>

Table 2-26A Appendix 2-AA does separate out subdivision capital from other contributed capital. The amounts listed on the Contributed Capital Sale of Transformers/Meters relates to the charge of transformers to new commercial developments. Transformers are capitalized to account 1850 and the recovery from the customer is credited to contributed capital. These two entries offset each other but are required to be kept in separate accounts for accounting purposes.

2.0-VECC-17
Reference: E2/pg. 64 / Appendix 2-G

a) Please update Appendix 2-G (Table 2-30) to include 2016 Actuals.

Response:

Appendix 2-G
Service Reliability and Quality Indicators
2011 - 2015

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
SAIDI	2.840	1.260	4.990	1.530	1.950	2.840	1.260	4.860	1.530	1.740	1.660	1.260	0.980	1.530	1.740
SAIFI	1.920	1.330	3.600	1.760	1.680	1.920	1.330	2.340	1.760	1.390	1.290	1.330	1.140	1.760	1.390
					2016					2016					2016
SAIDI					0.800					0.610					0.610
SAIFI					1.230					0.700					0.700

5 Year Historical Average

SAIDI	2.514	2.446	1.434
SAIFI	2.058	1.748	1.382

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	94.0%	100.0%	100.0%
High Voltage Connections	90.0%	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	99.9%	98.4%	99.0%	96.9%	98.5%	98.6%
Appointments Met	90.0%	99.7%	99.7%	99.4%	99.7%	98.5%	98.5%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	1.4%	1.5%	1.7%	2.4%	0.9%	1.0%
Appointment Scheduling	90.0%	100.0%	100.0%	99.8%	95.5%	94.0%	98.5%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

2.0-VECC-18
Reference: Appendix 2-A DSP /pg. 23 (PDF 109)

a) Please provide interruptions hours by cause code in the form of Figure 2-17 for 2016.

Response:

	2016 Hours	**%**
Adverse Weather	326	1.7
Defective Equipment	3,279	17.6
Foreign Interference	513	2.7
Loss of Supply	4,497	24.1
Scheduled Outage	7,363	39.1
Tree Contacts	1,479	7.9
Unknown	1,286	6.9
TOTAL	18,743	100.0

b) Please update the Summary of Defective Equipment outages to add 2016.

Response:

2016 Defective Equipment Hours

Fuses	310
Overhead Connections	217
Underground Cable	759
Switches	375
Transformers	1,126
Other	492
TOTAL	3,279

2.0-VECC-19
Reference: Appendix 2-A DSP /pgs. 66-68

a) **Please explain the term "useful life" as used in these charts. Specifically, is useful life measured by depreciation or by asset assessment? If the former, please explain what form of asset assessment is undertaken and whether a health index of major asset categories has been completed.**

Response:

Currently the term "useful life" used in these charts is associated with depreciation (e.g. Poles - 50 years). Welland Hydro plans to develop more formal asset assessment and health indices for the next Cost of Service Application.

b) **If an asset health index is available please provide a table showing, by asset category, the total asset population and the percentage of assets in good, fair and poor condition (or whatever asset condition characterization is used by Welland).**

Response:

There is no asset health index available at the present time.

2.0-VECC-20
Reference: Appendix 2-A DSP

a) Welland is proposing to significantly increase its annual capital expenditures as compared to the prior 5 years. What changes have happened occurred since the last cost of service application in distribution planning which support the request for the greater amount of capital spending?

Response:

Welland Hydro filed a revised Chapter 2 Appendix 2-AA in response to Board Staff 2-14. The total actual capital spending for the 2012-2016 five-year period totaled $11,215,390. The revised total capital spending for the five-year period from 2017-2021 is $11,898,986. Included in the next five-year period is $120,000 in capital spending for MIST meters mandated by the OEB. When this is removed from the equation the increase over the five-year period is 5.0%. The increase can be attributable to year over year inflation and difference is US-Canadian exchange rates over the two five year periods.

b) Please explain what new asset information has been gathered since the last cost of service application which supports this increase.

Response:

See response to (a) above.

c) Did Welland develop its distribution plan in-house?

Response:

Welland Hydro used engineering consulting firms to assist in the development of the distribution plan.

d) Has Welland had a third party review its distribution system plan? If yes, please provide that party's report on the plan.

Response:

As indicated in response to (c) above the final plan was reviewed by an outside engineering firm.

2.0-VECC-21
Reference: Appendix 2-A DSP/ Tables 5-35

a) **Please show how the implementation of the asset replacements as shown in Table 5-35 would impact asset useful lives by recasting Figures 5-32 to 5-34 to show the expected results at the end of 2021.**

Response:

Welland Hydro currently does not have the data available to recast Figures 32-34 for all the assets replaced during the forecast period ending in 2021.

2.0-VECC-22
Reference: E2/pg.22 – Continuity Schedules

a) Please update Tables 2-13 and 2-14 (Fixed Asset Continuity Schedules) to show 2016 actual results and any resulting change in 2017 fixed assets.

<u>Response:</u>

See response to Board Staff 4-13 (c).

Exhibit 3 – Operating Revenue

Board Staff – Exhibit 3

3-Staff-46
Ref: Section 2.3.3 Other Revenue, Table 3-37, Page 32

USoA #	USoA Description	2013 COS	2013 Actual	2014 Actual	2015 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
		2013	2013	2014	2015	2015	2016	2017
	Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Account Status Fees	$ 2,143	$ 976	$ 1,113	$ 1,078	$ 1,078	$ 1,096	$ 1,096
4235	NSF Charges	$ 4,253	$ 4,485	$ 4,200	$ 3,768	$ 3,768	$ 3,984	$ 3,984
4235	Occupancy Related	$ 95,564	$ 100,770	$ 105,746	$ 102,780	$ 102,780	$ 104,263	$ 104,263
4235	Disconnect/Reconnect	$ 19,622	$ 56,260	$ 54,828	$ 50,047	$ 50,047	$ 52,438	$ 52,438
4235	Markup Work Orders	$ 34,193	$ 23,474	$ 25,878	$ 30,217	$ 30,217	$ 28,048	$ 28,048
4235	**Total Specific Service Charges**	**$ 155,775**	**$ 185,965**	**$ 191,765**	**$ 187,890**	**$ 187,890**	**$ 189,829**	**$ 189,829**
4225	**Late Payment Charges**	**$ 71,971**	**$ 63,356**	**$ 74,709**	**$ 72,853**	**$ 72,853**	**$ 73,781**	**$ 73,781**
4082	Retail Services Revenues	$ 20,515	$ 20,155	$ 18,745	$ 17,071	$ 17,071	$ 10,339	$ 10,339
4084	Service Trans Revenues	$ 789	$ 498	$ 479	$ 377	$ 377	$ 377	$ 377
4086	SSA Administration	$ 61,575	$ 63,829	$ 64,764	$ 65,515	$ 65,515	$ 66,156	$ 66,774
4086	SSA Administration-Microfits	$ 1,425	$ 1,876	$ 2,840	$ 3,398	$ 3,398	$ 4,536	$ 10,800
4210	Rent from Property-Poles	$ 129,990	$ 130,448	$ 130,672	$ 139,958	$ 139,958	$ 139,958	$ 139,958
4210	Rent from Property-Buildings	$ 22,679	$ 22,617	$ 23,180	$ 23,644	$ 23,644	$ 24,117	$ 24,599
	Other Operating Revenue	**$ 236,973**	**$ 239,423**	**$ 240,680**	**$ 249,963**	**$ 249,963**	**$ 245,483**	**$ 252,847**
4305	Regulatory Credits	$ -	$ 95,589	$ 143,387	$ 143,382	$ 143,382	$ 143,382	$ -
4355	Gain/(Loss) Sale of Assets	$ 7,911	$ 10,119	$ 16,672	$ 184	$ 184	$ 8,428	$ 8,428
4355	Gain/(Loss) Early Retired Assets	$ -	$ -	$ -	$ -	$ -	$ -	-$ 29,320
4390	Scrap Metal Sales	$ 16,570	$ 33,853	$ 26,543	$ 23,992	$ 23,992	$ 25,268	$ 25,268
4390	Miscellaneous	$ 9,657	$ 4,277	$ 4,713	$ 3,909	$ 3,909	$ 4,311	$ 4,311
4405	Interest Income	$ 76,143	$ 102,840	$ 48,265	$ 38,381	$ 38,381	$ 9,811	$ 4,906
	Other Income or Deductions	**$ 110,281**	**$ 246,678**	**$ 239,580**	**$ 209,848**	**$ 209,848**	**$ 191,200**	**$ 13,593**
Specific Service Charges		**$ 155,775**	**$ 185,965**	**$ 191,765**	**$ 187,890**	**$ 187,890**	**$ 189,829**	**$ 189,829**
Late Payment Charges		**$ 71,971**	**$ 63,356**	**$ 74,709**	**$ 72,853**	**$ 72,853**	**$ 73,781**	**$ 73,781**
Other Operating Revenues		**$ 236,973**	**$ 239,423**	**$ 240,680**	**$ 249,963**	**$ 249,963**	**$ 245,483**	**$ 252,847**
Other Income or Deductions		**$ 110,281**	**$ 246,678**	**$ 239,580**	**$ 209,848**	**$ 209,848**	**$ 191,200**	**$ 13,593**
Total		**$ 575,000**	**$ 735,422**	**$ 746,734**	**$ 720,554**	**$ 720,554**	**$ 700,293**	**$ 530,050**

a) Please explain why interest forecast for 2016 and 2017 is significantly lower than in prior years.

Response:

The forecast for 2016 and 2017 exclude interest on RSVA accounts which are not included for rate making purposes. Cash reserves have been declining as capital expenditures exceed depreciation. Please see the answer to (b) for further explanation and details.

b) What was the 2016 actual interest amount?

Response:

	2013 Full Year COS	2013 Full Year Actual	2014 Full Year Actual	2015 Full Year Actual	2016 Bridge Year	2016 Full Year Actual	2017 Test Year
Interest Earned							
Interest Income-Bank & Miscellaneous	76,143	83,170	34,120	29,155	9,811	21,282	4,906
Interest Variance Accounts	0	19,670	14,145	9,226	0	2,972	0
4405 Interest and Dividend Income	76,143	102,840	48,265	38,381	9,811	24,254	4,906

Favourable RSVA variances in 2016 contributed to increased cash balances above forecast and increased interest income for the year.

3-Staff-47
Ref 1: Ex. 7, Page 8
Ref 2: Ex. 3, Page 14, Table 3-10 – Historical Annual Usage per Customer

At reference 1, Welland Hydro notes that it is proposing to eliminate its Large Use rate class since there are no longer any customers in that class since 2014. At reference 2, Welland Hydro shows historical annual usage for its Large User rate class for 2015 of 277,079 kWh.

Please explain this usage given Welland Hydro's statement that the Large User rate class had zero customers as of January 1, 2015.

Response:

The amount shown for the large user is just the difference between what was accrued (estimated) for the month of December, 2014 and the actual billed for the same period. The accrual is reversed in January, 2015 when the actual invoice for December, 2014 is issued.

SEC – Exhibit 3

3.0-SEC-15

Please explain the Applicant's strategy to reduce costs to maintain pace with declining billing determinants for some rate classes. If possible, please provide numerical targets that tie the rate of decline of billing determinants to the rate of decline of costs.

Response:

Welland Hydro is concerned about declining volumes with particular emphasis related to the GS>50 kW class. An updated load forecast showing 2016 Actuals has been submitted with responses to interrogatories. It shows that volumes for this class have been fairly constant since 2012. With the addition of GE at some time during 2018 it is hoped that additional activities will take place within both the GS<50 and GS>50 customer classes. Billing determinants in the Residential class will be tied to customer count by 2019. The loss of the last remaining Large Use class is reflected in this rate application.

The strategy for Welland Hydro going forward will be to find additional costs reductions related to Billing and Administrative for the next Cost of Rate Application. This will have to be done in correlation with the immediate need to plan for the loss of significant senior management experience and knowledge. This process has already started in 2017 with the addition of an engineering positon with emphasis on asset management procedures and gaining a detailed knowledge concerning Welland Hydro's distribution system. Welland Hydro believes there is a strong desire amongst its customers that Welland Hydro remain independent. As a result, one option that must be reviewed in depth is aligning Welland Hydro to share services with a larger LDC for items such as billing which will be initiated before the 2022 COS Rate Application. Although though targets are not possible to quantify at this point it would have to be in the form of reduced FTEs (as was the case from the 2013 COS to the 2017 COS) and possible reductions in software maintenance costs. Costs related to any upgrades related to Cybersecurity are unknown at this time but could be mitigated with shared services with an LDC with an internal IT department.

VECC – Exhibit 3

3.0 –VECC -23
Reference: Exhibit 3, page 5 (lines 8-9); page 12 (Table 3-7) and page 13 (Table 3-9)

a) **Please explain how the "average" customer/connection count for each year was determined (e.g. monthly averages, average of opening and closing year values, etc.).**

Response:

Monthly Averages (12 months)

b) **Please provide the actual 2016 customer/connection count for each customer class calculated on a similar basis.**

Response:

See the Table below for 2016 customer/connection count and 2016 actual volume per customer class.

Welland Hydro Weather Normal Load Forecast for 2017 Rate Application

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Weather Normal
Actual kWh Purchases	522,661,540	497,113,270	501,185,430	520,774,860	488,381,990	493,927,030	487,062,910	419,617,213	443,594,623	451,220,848	421,671,164	415,369,616	391,554,997	372,480,930	380,580,438	
Predicted kWh Purchases	511,805,225	499,154,221	495,428,251	517,268,239	493,008,135	487,401,509	468,907,143	451,463,012	458,122,161	446,630,634	429,367,603	409,179,240	385,553,066	379,011,802	374,896,619	363,458,017
% Difference	-2.1%	0.4%	-1.1%	-0.7%	0.9%	-1.3%	-3.7%	7.6%	3.3%	-1.0%	1.8%	-1.5%	-1.5%	1.8%	-1.5%	
CDM Purchase Adjustment																(2,264,923)
Predicted kWh Purchases after CDM																361,193,094
Billed kWh	502,676,916	477,862,795	484,141,790	501,866,998	476,790,671	468,834,412	467,645,348	397,504,327	425,977,887	429,972,781	405,481,205	399,002,323	380,885,629	356,369,056	363,388,525	346,852,851
By Class																
Residential																
Customers	18,178	18,298	18,498	18,756	18,915	18,996	19,137	19,277	19,434	19,717	20,110	20,266	20,472	20,636	20,823	21,025
kWh	163,758,008	157,611,434	158,198,542	170,925,879	160,694,398	162,856,080	157,944,948	152,428,518	159,733,338	158,621,921	159,179,968	158,724,607	158,185,053	157,973,719	163,109,690	158,180,520
General Service < 50 kW																
Customers	1,680	1,684	1,683	1,691	1,668	1,657	1,676	1,690	1,691	1,691	1,699	1,699	1,743	1,769	1,771	1,777
kWh	47,941,435	46,463,108	49,935,622	52,581,299	50,343,291	53,416,948	55,072,082	54,644,526	54,185,000	54,435,719	50,022,065	52,726,527	53,903,009	54,312,604	53,545,593	51,585,867
General Service 50 to 4,999 kW																
Customers	239	236	217	208	209	194	176	171	172	170	173	173	165	159	159	154
kWh	220,590,238	148,754,541	145,858,311	147,125,296	146,968,683	163,224,573	145,113,727	135,381,161	144,932,476	150,174,158	141,440,866	138,149,957	144,192,534	139,796,962	143,431,671	134,086,770
kW	551,946	449,454	418,533	415,116	414,301	441,184	417,425	390,493	432,238	417,210	387,769	389,545	402,375	402,768	396,528	377,726
Large User																
Customers	1	3	3	3	3	2	3	3	1	1	1	1	1	1	0	0
kWh	64,185,901	118,136,694	123,252,607	124,361,165	111,878,086	82,520,777	102,682,486	48,153,613	60,389,409	59,993,492	48,424,320	44,784,691	20,367,511	277,079	0	0
kW	193,768	293,338	287,801	296,227	313,394	248,610	271,979	195,437	168,338	170,236	152,573	153,121	59,144	479	0	0
Street Lights																
Connections	6,412	6,458	6,471	6,520	6,558	6,610	6,671	6,709	6,738	6,739	6,749	6,779	6,784	6,793	6,825	6,856
kWh	4,578,874	4,648,825	4,671,053	4,673,771	4,688,652	4,691,239	4,724,654	4,691,957	4,700,576	4,730,347	4,479,319	2,844,301	2,503,378	2,284,687	1,575,426	1,286,433
kW	11,857	12,975	13,024	13,039	13,084	13,086	13,186	13,091	13,119	13,148	12,420	7,923	6,992	6,476	4,561	3,582
Sentinel Lights																
Connections	765	758	750	739	732	704	689	680	679	663	627	580	519	515	509	509
kWh	608,625	1,025,571	1,029,432	1,000,000	1,010,963	980,631	949,655	1,052,725	908,962	894,240	849,278	782,990	767,199	753,964	749,437	749,437
kW	2,536	2,929	3,192	2,844	2,812	3,042	2,690	3,631	2,816	2,462	2,331	2,186	2,120	2,077	2,061	2,061
Unmetered Scattered Loads																
Connections	225	229	232	234	233	232	232	231	227	226	221	236	259	257	261	261
kWh	1,013,836	1,222,622	1,196,223	1,199,588	1,206,598	1,144,163	1,157,796	1,151,826	1,128,127	1,122,904	1,085,389	989,250	966,945	970,041	976,708	963,825
Total of Above																
Customer/Connections	27,500	27,665	27,854	28,151	28,317	28,396	28,583	28,760	28,943	29,207	29,580	29,733	29,944	30,129	30,347	30,583
kWh	502,676,916	477,862,795	484,141,790	501,866,998	476,790,671	468,834,412	467,645,348	397,504,327	425,977,887	429,972,781	405,481,205	399,002,323	380,885,629	356,369,056	363,388,525	346,852,851
kW from applicable classes	760,106	758,696	722,549	727,226	743,591	705,922	705,280	602,652	616,511	603,056	555,093	552,775	470,631	411,800	403,150	383,369
Total from Model																
Customer/Connections	27,500	27,665	27,854	28,151	28,317	28,396	28,583	28,760	28,943	29,207	29,580	29,733	29,944	30,129	30,347	30,583
kWh	502,676,916	477,862,795	484,141,790	501,866,998	476,790,671	468,834,412	467,645,348	397,504,327	425,977,887	429,972,781	405,481,205	399,002,323	380,885,629	356,369,056	363,388,525	346,852,851
kW from applicable classes	760,106	758,696	722,549	727,226	743,591	705,922	705,280	602,652	616,511	603,056	555,093	552,775	470,631	411,800	403,150	383,369

c) Did the Large Use customer cease operation in 2015 or was it transferred to another customer class for 2016?

<u>Response:</u>

The Large Use customer was transferred to GS>50 class effective January 1, 2015. Actual demand decreased by over 95% upon the plant ceasing production.

3.0 –VECC -24
Reference: Exhibit 3, pages 2 and 8-9

a) Do the purchased power values used by Welland in its regression model include purchases from microFIT, FIT or other forms of local generation? If not, what would the monthly purchases of such generation be for the period 2002 to 2015?

Response:

The purchased power values used by WHESC in its regression model include purchases from microFIT, FIT or other forms of local generation.

b) Did Welland test to see whether customer count or an economic activity variable such as GDP or employment would be a statistically significant explanatory variable? If yes, what were the results? If not, why not?

Response:

Yes, WHESC did test Number of Customers and the Ontario Real GDP as explanatory variables. Number of Customers was rejected as it had a negative coefficient which was counter intuitive. Ontario Real GDP was rejected since the t-stat was around 0.10 showing that it lacked statistical significance.

c) One would intuitively expect the CDM Activity variable to have a coefficient reasonably close to -1.0. Can Welland explain why the coefficient in its model is materially less than this (i.e., -7.6)?

Response:

The coefficient on the CDM Activity is assigned by the regression analysis which makes it difficult to explain exactly what the coefficient represents. However, WHESC believes the coefficient is addressing at least two issues. The first issue relates to the difference between net and gross CDM results. The CDM variable is based on net results but it is the gross results (i.e. the net amount plus free ridership) that impact the actual load. The second issue reflects that in addition to the difference between net and gross CDM results this variable could be picking up some of the economic downturn in the WHESC service area.

d) Please provide: i) the actual purchases for 2016; ii) the actual HDD and CDD value for 2016 and iii) the predicted purchases for 2016 using Welland's load forecast model.

Response:

WHESC's load forecast model has been revised to include 2016 actual data as historical source data for the 2017 forecast. The load forecast has also been revised to address the issue raised in 3.0 VECC 26 a). The actual purchases for 2016; ii) the actual HDD and CDD value for 2016 and iii) the predicted purchases for 2016 using WHESC's revised load forecast model are shown in the table below by month.

	Actual Purchases	Heating Degree Days	Cooling Degree Days	Predicted Purchases
Jan-16	33,086,719	657	0	33,441,891
Feb-16	30,387,692	587	0	31,152,421
Mar-16	29,517,636	449	0	30,932,382
Apr-16	27,543,104	353	0	28,670,340
May-16	28,092,239	145	24	29,035,817
Jun-16	32,022,793	29	52	30,429,598
Jul-16	38,626,684	0	141	37,291,519
Aug-16	41,485,017	0	159	39,497,219
Sep-16	31,934,437	34	47	28,514,669
Oct-16	27,675,720	185	5	26,782,356
Nov-16	28,120,166	357	0	27,761,732
Dec-16	32,088,231	568	0	31,386,676

3.0 –VECC -25
Reference: Exhibit 3, page 9 (lines 21-31)

a) Please provide a clean (and more legible) copy of Appendix 4-H.

Response:

A PDF copy of Appendix 4-H has been filed with responses to interrogatories.

b) Please provide Welland's 2015-2020 CDM Plan (page 9, line 29).

Response:

A PDF copy of Welland's 2015-2020 CDM Plan submitted to the IESO has been filed with responses to interrogatories.

c) Please provide the 2006-2010 Final CDM Results report for Welland (page 9, line 27). If this report does not contain the persisting impacts of 2006-2010 CDM programs through to 2015 please provide the IESO (or other source) used for this information.

Response:

The 2006-2010 Final CDM Results report for WHESC has been provided in live Excel format in file named "2006-2010 Final OPA CDM Results. Welland Hydro-Electric System Corp."

d) Please provide the IESO Report for Welland's Actual Verified 2015 CDM Results along with any reports from the IESO regarding the persisting effects of verified 2015 CDM programs.

Response:

The IESO Report for WHESC's Actual Verified 2015 CDM Results has been provided in live Excel format in file named "Final 2015 Annual Verified Results Report Welland Hydro-Electric System Corp._20160630".

3.0 –VECC -26
Reference: Exhibit 3, page 9 (lines 21-31)
Load Forecast Model - CDM Tab (Excel file)
Welland 2011-2014 CDM Results with Persistence (Excel file)

a) Please confirm that in determining the CDM variable the first-year savings from 2011-2014 CDM programs were not adjusted to reflect savings adjustments made in subsequent years (e.g., the 2011 CDM program savings used for 2011 were 2,018,776 kWh and did not include the 279,457 kWh adjustment for 2011 recorded in 2012).

Response:

Confirmed

b) Please re-calculate the historical CDM savings variable to account for this issue and to update the 2015 CDM savings for the actual verified 2015 CDM results.

Response:

This has been done and reflected in the response to c).

c) Based on the results in part (b) and any revisions required to historic purchased power values to account for local generation, please re-estimate the load forecast equation and provide the results (i.e., equation and regression statistics) along with revised versions of Tables 3-2, 3-5, 3-6 and 3-18 as well as the supporting load forecast model file.

Response:

As outlined in response to 3.0 VECC 24 d) WHESC has revised the load forecast model to reflect the results of part b) and include 2016 actual data as historical source data. Tables 3-2, 3-5, 3-6 and 3-18 from the revised load forecast model are provided below. The load forecast model has been filed in a live Excel format.

Table 3-2: Summary of Load and Customer/Connection Forecast

Year	Billed Actual (GWh)	Growth (GWh)	Billed Weather Normal (GWh)	Growth (GWh)	Customer/ Connection Count	Growth
Billed Energy (GWh) and Customer Count / Connections						
2013 Board Approved			421.6		29,847	
2002	502.7		490.6		27,500	
2003	477.9	(24.8)	478.2	(12.4)	27,665	165
2004	484.1	6.3	489.3	11.0	27,854	189
2005	501.9	17.7	484.3	(5.0)	28,151	297
2006	476.8	(25.1)	476.8	(7.5)	28,317	166
2007	468.8	(8.0)	465.9	(10.9)	28,396	79
2008	467.6	(1.2)	473.6	7.7	28,583	187
2009	397.5	(70.1)	407.7	(66.0)	28,760	177
2010	426.0	28.5	427.6	19.9	28,943	183
2011	430.0	4.0	429.6	2.0	29,207	264
2012	405.5	(24.5)	409.7	(19.9)	29,580	373
2013	399.0	(6.5)	401.9	(7.8)	29,733	153
2014	380.9	(18.1)	385.1	(16.8)	29,944	212
2015	356.4	(24.5)	359.7	(25.4)	30,129	184
2016	363.4	7.0	357.2	(2.6)	30,347	218
2017 Test			346.9	(10.3)	30,583	236

Table 3-5: Statistcial Results

R Square	90.3%
Adjusted R Square	90.0%
F Test	269.7
MAPE (Monthly)	3.5%
T-stats by Coefficient	
Heating Degree Days	13.4
Cooling Degree Days	16.1
Number of Days in Month	4.1
CDM Activity	(30.1)
Number of Peak Hours	3.0
Spring Fall Flag	(2.4)
Constant	1.4

Table 3-6: Total System Purchases Excluding Large Use

Year	Actual	Predicted	% Difference	Predicted Weather Normal	Weather Normal Conversion Factor	Actual Weather Normal
Purchased Energy (GWh)						
2002	522.7	511.8		499.5	0.9760	510.1
2003	497.1	499.2	0.4%	499.5	1.0008	497.5
2004	501.2	495.4	(1.1%)	500.7	1.0106	506.5
2005	520.8	517.3	(0.7%)	499.1	0.9649	502.5
2006	488.4	493.0	0.9%	493.0	1.0000	488.4
2007	493.9	487.4	(1.3%)	484.4	0.9938	490.9
2008	487.1	468.9	(3.7%)	474.9	1.0128	493.3
2009	419.6	451.5	7.6%	463.0	1.0256	430.4
2010	443.6	458.1	3.3%	459.9	1.0038	445.3
2011	451.2	446.6	(1.0%)	446.3	0.9992	450.9
2012	421.7	429.4	1.8%	433.8	1.0104	426.1
2013	415.4	409.2	(1.5%)	412.1	1.0072	418.4
2014	391.6	385.6	(1.5%)	389.8	1.0111	395.9
2015	372.5	379.0	1.8%	382.6	1.0095	376.0
2016	380.6	374.9	(1.5%)	368.5	0.9829	374.1
2017 Test		363.5		363.5	1.0000	
2017 WN - 10 year average		361.0				
2017 WN - 20 year trend		361.9				

Table 3-18: Alignment of Non-normal to Weather Normal Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Large User	Street Lights	Sentinel Lights	Unmetered Scattered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2017 Test - Forecast	164.7	53.7	139.3	0.0	1.6	0.7	1.0	361.0
Weather Adjustment (GWh)								
2017 Test - Forecast	(6.0)	(2.0)	(4.0)	0.0	0.0	0.0	0.0	(12.0)
CDM Adjustment (GWh)								
2017 Test - Forecast	(0.5)	(0.2)	(1.2)	0.0	(0.3)	0.0	0.0	(2.2)
Weather Normalized Billed Energy Forecast (GWh)								
2017 Test - Forecast	158.2	51.6	134.1	0.0	1.3	0.7	1.0	346.9

3.0 –VECC -27
Reference: Exhibit 3, page 6 (Table 3-3); pages 14-16 and page 19

a) Please provide the actual billed energy (and kW where applicable) by rate class for 2016.

Response:

See Response to 3.0–VECC– 23(b).

b) Please update Table 3-10 to include actuals for 2016.

Response:

Table 3-10: Historical Annual Usage per Customer

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Large User	Street Lights	Sentinel Lights	Unmetered Scattered Loads
Annual kWh Usage Per Customer/Connection							
2002	9,009	28,545	921,365	48,139,425	714	796	4,501
2003	8,614	27,585	630,984	42,958,798	720	1,353	5,349
2004	8,552	29,672	673,710	43,500,920	722	1,372	5,147
2005	9,113	31,098	707,333	43,892,176	717	1,353	5,126
2006	8,496	30,182	704,886	37,292,695	715	1,380	5,188
2007	8,573	32,247	840,642	34,146,528	710	1,392	4,939
2008	8,254	32,854	823,340	41,072,994	708	1,378	4,990
2009	7,907	32,331	792,862	19,261,445	699	1,549	4,997
2010	8,219	32,049	841,001	45,292,057	698	1,338	4,964
2011	8,045	32,195	884,751	59,993,492	702	1,348	4,962
2012	7,916	29,445	816,397	48,424,320	664	1,355	4,918
2013	7,832	31,043	800,096	44,784,691	420	1,349	4,201
2014	7,727	30,928	871,693	20,367,511	369	1,478	3,729
2015	7,655	30,701	880,149	277,079	336	1,464	3,779
2016 Actuals	7,833	30,235	902,086	0	231	1,472	3,742

c) Please re-do Tables 3-12, 3-13 and 3-18 using the 2016 actual usage per customer as the basis for the customer class forecasts.

Response:

Tables 3-12 and 3-13 from the revised WHESC load forecast are provided below which uses the 2016 actual usage per customer as the basis for the customer class forecasts. Table 3-18 is provided above in response to 3.0 VECC 26 c)

Table 3-12: Annual kWh Usage per Customer/Connection							
Year	**Residential**	**General Service < 50 kW**	**General Service 50 to 4,999 kW**	**Large User**	**Street Lights**	**Sentinel Lights**	**Unmetered Scattered Loads**
Annual kWh Usage per Customers/Connection							
2016 Actual	7,833	30,242	902,086	0	231	1,473	3,737
2017 Test - Forecast	7,833	30,242	902,086	0	231	1,473	3,688

Table 3-13: Non-normalized Weather Billed Energy Forecast								
Year	**Residential**	**General Service < 50 kW**	**General Service 50 to 4,999 kW**	**Large User**	**Street Lights**	**Sentinel Lights**	**Unmetered Scattered Loads**	**Total**
NON-normalized Weather Billed Energy Forecast (GWh)								
2017 Test - Forecast	164.7	53.7	139.3	0.0	1.6	0.7	1.0	361.0

3.0 –VECC -28
Reference: Exhibit 3, pages 32-33

a) Please update Table 3-37 for actual (unaudited) 2016 values.

<u>Response</u>:

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 COS	2013 Actual	2014 Actual	2015 Actual[2]	Actual Year[2]	Actual Year[2]	Bridge Year[2]	Test Year
		2013	2013	2014	2015	2015	2016	2016	2017
	Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Account Status Fees	$ 2,143	$ 976	$ 1,113	$ 1,078	$ 1,078	$ 1,382	$ 1,096	$ 1,096
4235	NSF Charges	$ 4,253	$ 4,485	$ 4,200	$ 3,768	$ 3,768	$ 4,119	$ 3,984	$ 3,984
4235	Occupancy Related	$ 95,564	$ 100,770	$ 105,746	$ 102,780	$ 102,780	$ 107,970	$ 104,263	$ 104,263
4235	Disconnect/Reconnect	$ 19,622	$ 56,260	$ 54,828	$ 50,047	$ 50,047	$ 55,706	$ 52,438	$ 52,438
4235	Markup Work Orders	$ 34,193	$ 23,474	$ 25,878	$ 30,217	$ 30,217	$ 28,565	$ 28,048	$ 28,048
4235	**Total Specific Service Charges**	**$ 155,775**	**$ 185,965**	**$ 191,765**	**$ 187,890**	**$ 187,890**	**$ 197,742**	**$ 189,829**	**$ 189,829**
4225	**Late Payment Charges**	**$ 71,971**	**$ 63,356**	**$ 74,709**	**$ 72,853**	**$ 72,853**	**$ 77,313**	**$ 73,781**	**$ 73,781**
4082	Retail Services Revenues	$ 20,515	$ 20,155	$ 18,745	$ 17,071	$ 17,071	$ 14,841	$ 10,339	$ 10,339
4084	Service Trans Revenues	$ 789	$ 498	$ 479	$ 377	$ 377	$ 251	$ 377	$ 377
4086	SSA Administration	$ 61,575	$ 63,829	$ 64,764	$ 65,515	$ 65,515	$ 67,284	$ 66,156	$ 66,774
4086	SSA Administration-Microfits	$ 1,425	$ 1,876	$ 2,840	$ 3,398	$ 3,398	$ 5,010	$ 4,536	$ 10,800
4210	Rent from Property-Poles	$ 129,990	$ 130,448	$ 130,672	$ 139,958	$ 139,958	$ 141,277	$ 139,958	$ 139,958
4210	Rent from Property-Buildings	$ 22,679	$ 22,617	$ 23,180	$ 23,644	$ 23,644	$ 24,057	$ 24,117	$ 24,599
	Other Operating Revenue	**$ 236,973**	**$ 239,423**	**$ 240,680**	**$ 249,963**	**$ 249,963**	**$ 252,720**	**$ 245,483**	**$ 252,847**
4305	Regulatory Credits	$ -	$ 95,589	$ 143,387	$ 143,382	$ 143,382	$ 143,352	$ 143,382	$ -
4355	Gain/(Loss) Sale of Assets	$ 7,911	$ 10,119	$ 16,672	$ 184	$ 184	$ 7,934	$ 8,428	$ 8,428
4355	Gain/(Loss) Early Retired Assets	$ -	$ -	$ -	$ -	-$ 35,287	-$ 47,497	$ -	-$ 29,320
4390	Scrap Metal Sales	$ 16,570	$ 33,853	$ 26,543	$ 23,992	$ 23,992	$ 32,269	$ 25,268	$ 25,268
4390	Miscellaneous	$ 9,657	$ 4,277	$ 4,713	$ 3,909	$ 3,909	$ 789	$ 4,311	$ 4,311
4405	Interest Income	$ 76,143	$ 102,840	$ 48,265	$ 38,381	$ 38,381	$ 24,254	$ 9,811	$ 4,906
	Other Income or Deductions	**$ 110,281**	**$ 246,678**	**$ 239,580**	**$ 209,848**	**$ 174,561**	**$ 161,101**	**$ 191,200**	**$ 13,593**
Specific Service Charges		**$ 155,775**	**$ 185,965**	**$ 191,765**	**$ 187,890**	**$ 187,890**	**$ 197,742**	**$ 189,829**	**$ 189,829**
Late Payment Charges		**$ 71,971**	**$ 63,356**	**$ 74,709**	**$ 72,853**	**$ 72,853**	**$ 77,313**	**$ 73,781**	**$ 73,781**
Other Operating Revenues		**$ 236,973**	**$ 239,423**	**$ 240,680**	**$ 249,963**	**$ 249,963**	**$ 252,720**	**$ 245,483**	**$ 252,847**
Other Income or Deductions		**$ 110,281**	**$ 246,678**	**$ 239,580**	**$ 209,848**	**$ 174,561**	**$ 161,101**	**$ 191,200**	**$ 13,593**
Total		**$ 575,000**	**$ 735,422**	**$ 746,734**	**$ 720,554**	**$ 685,267**	**$ 688,876**	**$ 700,293**	**$ 530,050**

Account 4405 - Interest and Dividend Income

	2013 Cos	2013 Actual	2014 Actual	2015 Actual[2]	Actual Year[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2013	2013	2014	2015	2015	2016	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Short-term Investment Interest								
Bank Deposit Interest	$ 76,143	$ 83,170	$ 34,120	$ 29,155	$ 29,155	$ 21,282	$ 9,811	$ 4,906
Miscellaneous Interest Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA Interest Income		$ 19,670	$ 14,145	$ 9,226	$ 9,226	$ 2,972	$ -	$ -
Total	**$ 76,143**	**$ 102,840**	**$ 48,265**	**$ 38,381**	**$ 38,381**	**$ 24,254**	**$ 9,811**	**$ 4,906**

b) Is the "loss" recorded in Account 4355 for 2017 a one-time event?

<u>Response</u>:

The loss recorded in Account 4355 is not a one-time event. It is meant to estimate the annual amount of write-offs associated with premature failure of assets which were previously pooled under CGAAP and now an expense under IFRS. Welland Hydro has treated it as a reduction to account 4355. Welland Hydro has adjusted 4355 Gain/(Loss) to reflect actual losses in 2015 and 2016. These have been charged to account 1575 for RRR reporting purposes.

Exhibit 4 – Operating Expenses

Board Staff – Exhibit 4

4-Staff-48
Ref: Chapter 2 Appendices, Tab 2-JA

The proposed OM&A costs in 2017 of $6,999,907 represent an increase of $806,447 or 13% over the 2013 actual OM&A.

a) Please identify any customer engagement relating specifically to the increase in OM&A that supports the increases proposed in this application.

Response:

WHESC presented OM&A and Capital Expenditure information in absolute estimated investment dollars. However, both budget items were consulted to assess reaction to estimated rate impacts.

Before hearing the set of questions on assessing the plan, residential customers were presented with the following information:

> *"**Welland Hydro** believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Between 2017 and 2021, **Welland Hydro**'s proposed plan will see it …*
>
> - *spend an estimated **$36.4 million** on on-going maintenance and the operation of the distribution system; and*
> - *invest an estimated **$12.1 million** in new equipment and infrastructure priorities that will help ensure system reliability.*
>
> *To fund this plan, **Welland Hydro** is proposing the **average residential customers' rate increase by approximately $0.88 per month** on the distribution portion of their bill over the next five years.*
> *So, in five years, by 2021, the average residential household will be paying an **estimated $4.38** more per month on the distribution portion of its electricity bill."*

After hearing these cost considerations, more than 7-in-10 (71%) would give social permission for the rate increase. Overall, a third (34%) feel the rate increase is reasonable and support it; less than 4-in-10 (38%) "don't like it, but think it's necessary" and less than 1-in-4 (23%) oppose it.

- Those residential customers who feel impacted by their electricity bill (66%) are less likely to give permission than those who don't feel their electricity bill is a source of financial difficulty (84%).

- Low (77%) and Medium-low (75%) consumption residents are a bit more likely to support the rate increase than higher consumption residents (Medium-high: 69%; High: 65%).

b) Further, how has the Applicant communicated these benefits to its customers, and how did customers respond? Please provide some examples, including any customer feedback. If no communications took place, please explain why not.

Response:

WHESC did not specifically communicate the benefits of its proposed OM&A spend with customers following the final phase of its customer engagement activities. With a majority of customers providing social permission to move ahead with the proposed plan, WHESC has not deemed immediate custom communications on this topic a priority. That said, it is likely that OM&A along with other drivers of rate change will be communicated with customers on an on-going basis moving forward.

c) Please identify what, if any, improvements in services and outcomes the applicant's customers will experience in 2017 and during the subsequent IRM term as a result of increasing the provision for OM&A at the rate indicated.

Response:

The 2017 COS OM&A levels will allow Welland Hydro to maintain its scorecard performance metrics and the excellent customer service Welland Hydro's customers currently experience. The 2017 COS Rate Application also includes succession planning without increasing FTEs. On-line customer self-service options have been removed from the plan as a result of feedback from customers. Welland Hydro has been working on an outage management application that it plans to make available to customers in 2017. This outage management application is currently being used by line and control room staff to improve responses and reduce outage durations.

d) Please identify any initiatives considered and/or undertaken by Welland Hydro, including any analysis conducted, to optimize plans and activities from a cost perspective.

Response:

As indicated in the rate application Welland Hydro has reduced the number of FTEs by two from the 2013 Cost of Service Application to 2016 Actual. The savings related to these reductions are outlined in Table 4-2 from Exhibit 4. In addition to the reduction of two FTEs Welland Hydro successfully negotiated changes to Employee Post Retirement which will reduce these costs as employees with these benefits retire.

e) What improvements did Welland Hydro experience with specific programs up to 2016, and what new productivity and/or efficiency improvement programs are planned? What are the planned savings?

<u>Response</u>:

Welland Hydro outlined costs savings programs up to 2016 in response to (d) above. Although though not a cost reduction, the elimination of a full-time vehicle mechanic in the 2017 Test is a cost avoidance to offset the addition of an engineer. Going forward Welland Hydro will have to undertake further reviews for efficiencies and will explore shared service agreements with other LDCs with an emphasis on billing costs and software maintenance costs.

4 -Staff-49
Ref: Ex.4, Page 11, Table 4-4 – Cost Drivers Table

Welland Hydro's bad debt expense shows a jump of $53k in the 2016 column of Welland Hydro's OM&A drivers cost table. The 2017 test year shows a slight increase of $2,300.

Please explain the cause of the large increase in Bad Debt Expense in 2016, and why it is anticipated to decrease in 2017.

Response:

Table 4-4 is year over year changes since the 2013 COS and can be summarized as follows:

	Total Change	
2013 Cost of Service	$84,335	
2013 Actual	$86,306	$1,971
2014 Actual	$150,594	$64,288
2015 Actual	$61,809	($88,785)
2016 Bridge	$115,000	$53,191
2017 Test	$117,300	$2,300
		$32,965

The increase in 2014 and decrease in 2015 are related to the bankruptcy of a large commercial retailer. In 2014, the balance owing from the retailer was reflected in bad debt expense to recognize the potential loss. A receivables insurance claim was filed and approved in 2015 which recovered a significant portion of the amount expensed in 2014. As a result, actual bad debt expense was overstated in 2014 and understated in 2015. This accounts for the increase in the 2016 Test Year. See 4.0-VECC-30 below for additional information related to bad debt expense.

4-Staff-50
Compensation Benchmarking – Unionized Positions Ref 1: Ex.4, Page 27
Ref 2: Ex.4, Page 28

At reference 1, Welland Hydro discusses its compensation system for unionized positions. Welland Hydro discusses the objectives and outcomes when the 2015 contract negotiations took place.

At reference 2, Welland Hydro discusses its compensation system for management positions. Welland Hydro notes that it benchmarks the salaried compensation outcomes with LDCs of a similar size in Ontario. Welland Hydro also participates in the annual compensation survey performed by MEARIE.

a) Please state whether or not Welland Hydro has ever had any formal studies of its compensation system conducted for unionized positions, either by or for the applicant. If yes, please provide such studies. If no, please explain why not.

Response:

A formal study of unionized positions has not been completed. WHESC has had their union positions rated in the Hay System used by other LDCs in Ontario. WHESC is part of a HR Network Group of 20 utilities that share information for union positions that includes the wage rates of the union positions and benefits provided to union employees (Collective Agreement Issues). During the 2015 contract negotiations Welland Hydro compared its compensation rates to other LDCs with an emphasis on neighbouring LDCs and lineman rates. Welland Hydro's current hourly pays rates for lineman are at the bottom end of rates paid by neighbouring LDCs.

b) Please explain the nature of the questions in the MEARIE survey and how compensation is benchmarked based on the results.

Response:

Welland Hydro participates in the Annual MEARIE Survey. Job descriptions for various management positions are provided by MEARIE. Welland Hydro chooses the closest match based on the job description and reports the current salary information for each position. Other information required of the survey is customer base, geographic region, operating budget, benefit programs, bonus programs if applicable, car allowances, salary increases, and number of full time employees.

WHESC benchmarks its management employee compensation against similar positions in other LDCs in the 20,000 to 40,000 customer range.

c) Did Welland Hydro conduct any benchmarking other than the above to support the current cost of service application?

<u>Response</u>:

Welland Hydro has not conducted other compensation benchmarking than those included in responses to (a) and (b) above.

4-Staff-51
Ref: Ex.4, Page 26
Ref: Chapter 2 Appendices, Tab 2-K

At the above references, FTE and Employee Costs are provided for the period from 2013 to 2017. In the two-year period 2015 to 2017 (forecasted), Total Management Compensation is shown as increasing from $1,566,055 to $1,888,792 (before OPEBs and unusual items), an increase of 21%, while Total Non-Management Compensation in the same period increased from $2,672,111 to $2,854,237, an increase of 7%.

Please explain this differential.

Response:

Total Management Compensation in 2015 is for 11 FTE's versus 13 FTE's for the 2017 Cost of Service Year. The Senior Accountant position was vacant for the majority of 2015 and is included in both the 2016 Bridge Year and 2017 Test Year. The increase of one additional management position in the 2017 Test Year is offset by a reduction of one union position. As a result, the 2015 Total Non-Management Compensation is for 29 FTE's and 2017 is for 28 FTE's.

4-Staff-52
Ref: Exhibit 4, Pages 35-37 and Appendix 4-B Actuarial Valuations Ref: Exhibit 2, Appendix 1-I, Annual Financial Statements

With regards to post-retirement benefits:

a) **Welland Hydro has used the cash basis for post-retirement benefits expense in the application. It will adopt the methodology that the OEB determines to be appropriate at the conclusion of the OPEBs consultation (EB-2015-0040).**

i. **If the OEB determines OPEBs are to be accounted for on a forecasted accrual basis during Welland Hydro's IR term, is Welland Hydro proposing to adopt the change during the IR term?**

<u>Response</u>:

Welland Hydro recommends a deferral account for either use of the cash or accrual methodology until the OEB makes a decision in EB-2015-0040.

ii. **If yes, how will Welland Hydro adopt the change?**

<u>Response</u>:

As per i) above the use of a deferred account should be used during the IRM period.

iii. **Why is Welland Hydro proposing to use the cash basis and not consistently use the accrual basis when the difference between the forecasted 2017 cash and accrual is not material?**

<u>Response</u>:

Welland Hydro was of the opinion that the cash basis is what the Board has suggested be used until the proceeding is completed. If Welland Hydro had been consistent with the 2013 COS and applied the accrual basis for accounting for OPEBs, it would result in a reduction of $3,075 in 2017 OM&A costs.

b) **In the 2015 financial statements, Note 25 shows an IFRS transition adjustment to reduce the post-employment benefit obligation by $104k. In Appendix 4-B, the chart in the cover letter shows a reduction in the obligation by $157k.**

i. **Please reconcile the post-employment benefit reduction of $104k in the 2015 financial statements and the $157k in the actuarial valuation.**

<u>Response</u>:

The chart in the cover letter in Appendix 4-B is referring to the entry required to restate the

December 31, 2013 balance for OPEBs under CICA 3461 prior to conversion to the IFRS methodology to ($1,654,941). The actual balance in the OPEB liability in the 2013 financial statements is ($1,601,974) as can be seen in the Appendix 4A. The $104K listed on page 36 of the 2015 statements is comprised of the following entries:

CICA 3461 versus IAS 19	$157,516
Adjustment ($1,654,941) from ($1,601,974)	($52,967)
Per 2015 Financial Statements Page 36	$104,549

The liability at the end of 2014 under CGAAP was $1,604,364 which can be found in Appendix 4-B on the page titled Estimated Benefits Expense (CICA 3461) Final Revised and on page 37 of the 2015 financial statements.

ii. **The $157k reduction in the actuarial valuation is composed of a reduction to the Accrued Benefit Obligation of $51k, a recognition of unrecognized past service costs of $18k and a recognition of actuarial loss of $88k. However, on page 7 of the actuarial report, the $88k is shown as an actuarial gain of $88k. Please clarify whether the amount is a gain or loss and if it increases or decreases the post-retirement obligation as at January 1, 2014.**

Response:

Page 7 of the actuarial report is still under CICA and is not used in the 2015 financial statements. The figures on page 37 and 38 of the 2015 financial statements reflect the change in the liability for 2014 from $1,497,425 to $1,601,323 which is found in Tab 4B under Estimated Benefit Expense (IAS19) later in the valuation report. They are composed of the following:

Other Comprehensive Loss	$113,167
Current Service/Interest/Benefits	(9,269)
Total Change	$103,898

Please note that the $9,269 is shown in the financial statement as $3K reduction in OPEB liability on page 37 of the 2015 financial statements and a ($12K) reduction in Employee salaries and benefits on page 38 of the 2015 financial statements.

iii. **Please also explain how the recognition of the unrecognized past service costs of $18k reduces the post-retirement obligation, instead of increasing the obligation.**

Response:

See response to i) and ii) above.

4-Staff-53
Ref: Tab "4. 2011-14 LRAM" of LRAMVA Work Form, Tables 7 to 10

As noted in the LRAMVA workform, adjustments should be applied to the same program year it relates to. For example, adjustments to 2011 results should be shown as part of the calculation of 2011 lost revenues.

Please confirm how the savings adjustments were applied to the verified results.

<u>Response</u>:

For example, it assumed the question relates to 2011 program results which are first recorded in 2012. In this case, these results would have assumed to occur in 2012 and not brought back to 2011. In other words, the referenced adjustment was not made.

4-Staff-54
LRAMVA

OEB staff notes that if the OEB approves a distributor's account balances on a final basis, any adjustments made to prior years by the IESO are not recoverable.

Is Welland Hydro expecting any retroactive adjustments from the IESO to its savings?

Response:

At his time, WHESC is not expecting any retroactive adjustments from the IESO to its savings. WHESC understands that if the OEB approves a distributor's account balances on a final basis, any adjustments made to prior years by the IESO are not recoverable. As a result, if retroactive adjustments from the IESO to its savings do occur WHESC understands they are not recoverable.

4-Staff-55
Ref: Tab "6. Persistence Rates" in Welland's LRAMVA Work Form
Tabs 1-4 of "Welland_2017_2011-2014 CDM Results with Persistence No DR_20161028"

a) **Please discuss how the persistence values in Table 12 of the LRAMVA Work Form were derived from the initiative persistence savings in file, "Welland_2017_2011-2014 CDM Results with Persistence No DR_20161028." Please provide any supporting evidence provided to Welland Hydro from the IESO (preferably in excel format). An excerpt of Table 12 is provided for reference below.**

Table 12 of LRAMVA Workform:

Table 12. Determination of 2011-2014 Persistence Rates

one year that will carry forward (or persist) into subsequent years.

Implementation Period	Annual Net Energy Savings (GWh) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2011 - Verified										
2012 - Verified										
2013 - Verified										
2014 - Verified										

Implementation Period	Persistence Factor (GWh) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2011		0.00	1.0000	0.9974	0.00	0.00	0.00	0.00	0.00	0.00
2012			1.0000	1.0000	0.00	0.00	0.00	0.00	0.00	0.00
2013				0.9993	0.00	0.00	0.00	0.00	0.00	0.00
2014					0.00	0.00	0.00	0.00	0.00	0.00

Implementation Period	Annual Net Peak Savings (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2011 - Verified										
2012 - Verified										
2013 - Verified										
2014 - Verified										

Implementation Period	Persistence Factor (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2011		0.00	1.0000	1.0000	0.00	0.00	0.00	0.00	0.00	0.00
2012			1.0000	1.0000	0.00	0.00	0.00	0.00	0.00	0.00
2013				0.9611	0.00	0.00	0.00	0.00	0.00	0.00
2014					0.00	0.00	0.00	0.00	0.00	0.00

Response:

The live Excel file named "Welland_2017_2011-2014 CDM Results with Persistence No DR Responses" (File #1) has been provided to respond to this question. For 2011 programs, the calculation of the kWh persistence factor of 1.0000 for 2013 and 0.9974 for 2014 is provided in File #1, Tab 2011, cells AT22 and AU22. These are the persistence factors applied to the Residential class results in Welland_2017_LRAMVA_Work_Form (File #2), Tab 4, cell H76. For the GS < 50 kW class, there is a hard-coded number used in File #2, Tab 4, cell I76 which represents the factor determined in File #1, Tab 2011, cell AU25. This factor applied to the Residential class persistence factor provides the persistence for the GS < 50 kW class. The calculation of the kW persistence factor for 2011 programs of 1.0000 for 2013 and 1.0000 for 2014 is provided in File #1, Tab 2011, cells P25 and Q25. This represents the persistence factor for GS > 50 kW class used in File #2, Tab 4, cell J76.

For 2012 programs, the calculation of the kWh persistence factor of 1.0000 for 2013 and 1.000 for 2014 is provided in File #1, Tab 2012, cells AS26 and AT26. These are the persistence factors applied to the Residential class results in File #2, Tab 4, cell H155. For the GS < 50 kW class, there is a hard-coded number used in File #2, Tab 4, cell I155 which represents the factor determined in File #1, Tab 2012, cell AT29. This factor applied to the Residential class persistence factor provides the persistence for the GS < 50 kW class. The calculation of the kW persistence factor for 2012 programs of 1.0000 for 2013 and 1.0000 for 2014 is provided in File #1, Tab 2012, cells O29 and P29. This represents the persistence factor for GS > 50 kW class used in File #2, Tab 4, cell J155.

For 2013 programs, the calculation of the kWh persistence factor of 0.9993 for 2014 is provided in File #1, Tab 2013, cell AU25. This is the persistence factor applied to the Residential class results in File #2, Tab 4, cell H235. For the GS < 50 kW class, there is a hard-coded number used in File #2, Tab 4, cell I235 which represents the factor determined in File #1, Tab 2013, cell AU28. This factor applied to the Residential class persistence factor provides the persistence for the GS < 50 kW class. The calculation of the kW persistence factor for 2013 programs of 0.9611 for 2014 is provided in File #1, Tab 2013, cell Q30. This represents the persistence factor for GS > 50 kW class used in File #2, Tab 4, cell J235.

b) In the 2011, 2012 and 2013 LRAM Work Forms (Tab 4. 2011-14 LRAM), OEB staff notes that a "persistence adjustment" was made to savings (i.e., cells I 76, I 155, and I 235 of Tab 4). Please show and explain how this adjustment was calculated and why it is applied to the persistence results. Please indicate if the IESO supported this adjustment and provide any supporting documentation if available.

Response:

Please see response to a).

4-Staff-56
Ref: Tab "4. 2011-14 LRAM" in Welland's LRAMVA Work Form Welland 2014 CDM Annual Report, Table 5a (Verified Results)

a) **Please confirm whether or not the initiative level savings input into the 2011, 2012, 2013 and 2014 LRAMVA Work Forms take into account any initiative level adjustments that were verified by the IESO/OPA. If they do, please confirm that the initiative level adjustments were provided to Welland Hydro by the IESO and submit the initiative level adjustments in excel format with this response.**

<u>Response</u>:

It is WHESC's understanding, that the initiative level savings input into the 2011, 2012, 2013 and 2014 LRAMVA Work Forms did not take into account any initiative level adjustments that were verified by the IESO/OPA.

b) **Please reconcile the business retrofit savings included in the LRAMVA Work Form in 2011, 2012, 2013 and 2014, as the savings amounts submitted by Welland Hydro vary with the IESO verified amounts significantly.**

<u>Response</u>:

The following table outlines how the retrofit savings included in the LRAMVA Work Form in 2011, 2012, 2013 and 2014 were determined. The values before allocation shown under the kW and kWh columns reconcile to the IESO verified result. These values are from the file named Welland_2017_2011-2014 CDM Results with Persistence No DR_20161028 filed with the Application.

Retrofit Program	kW	KWh	kW Allocation to GS > 50 kW	kWh Allocation to GS < 50 kW	GS > 50 kW Assigned kW	GS < 50 kW Assigned kWh
Pre-2011 Programs completed in 2011 Persistence into 2013 - Business	161	927,188	90%	10%	145	92,719
2011 Program Persistence into 2013 - Business	32	207,423	90%	10%	29	20,742
2011 Program Persistence into 2013 - Industrial	6	42,733	100%		6	
2012 Program Persistence into 2013 - Business	60	257,314	90%	10%	54	25,731
2013 Program - Business	330	2,543,024				
2012 Program 1st recorded in 2013 - Business	23	94,999				
2013 Total	353	2,638,023	90%	10%	318	263,802
2014 Program - Business	283	907,874				
2013 Program 1st recorded in 2014 - Business	54	188,606				
2014 Total	337	1,096,480	90%	10%	303	109,648

c) Please update the allocation of business retrofit savings to both the GS<50 kW and GS>50 kW classes for the 2011, 2012, 2013 and 2014 years, as currently, each rate class has an allocation of 100%. In doing so, please ensure that the business retrofit savings are entered in accordance with the IESO verified results.

<u>Response</u>:

The table provided in response to (b) outlines the Retrofit kW assigned to the GS > 50 kW class and the kWh assigned to GS < 50 kW class. These values have been entered in the LRAMVA Work Form for 2011, 2012, 2013 and 2014. The input values have been allocated 90% to GS > 50 kW class and 10% to GS < 50 kW class. This means the 100% allocator is needed in order to ensure these results are assigned to the correct class in the LRAMVA Work Form.

d) OEB staff has identified additional savings from other business and industrial programs that are not captured in the 2011, 2012, 2013 and 2014 LRAMVA Work Forms. Please discuss why all savings provided by the IESO have not been included in the LRAMVA Work Form. In the event that Welland Hydro did not input the final CDM results from the IESO correctly, please update the LRAMVA work form.

<u>Response</u>:

The source of data used to populate the LRAMVA Work Form was the filed named Welland_2017_2011-2014 CDM Results with Persistence No DR_20161028. This file is consistent with verified results from the IESO for 2011 to 2014 programs. The only programs not included LRAMVA were those related to demand response.

e) Please file a copy of the revised LRAMVA work form with the changes noted above.

<u>Response</u>:

The LRAMVA work form has been revised to address the issue raised in 4-Staff-53.

The LRAMVA claim has changed from $13,083.12 to $14,202.37.

The revised work form has been filed in live Excel format named as Welland_2017_LRAMVA_Work_Form_Responses.

SEC – Exhibit 4

4.0-SEC-16

[Ex. 4, p. 21] With respect to Table 4-9:

a) Please confirm that Salary and Wages per FTE for Management is proposed to increase from 2013 Actual to 2017 Forecast by 19.33%, a CAGR of 4.5% per year.

Response:

Confirmed.

b) Please confirm that Total Compensation per FTE for Management is proposed to increase from 2013 Actual to 2017 Forecast by 18.83%, a CAGR of 4.4% per year.

Response:

Confirmed.

c) Please confirm that Salary and Wages per FTE for Non-Management is proposed to increase from 2013 Actual to 2017 Forecast by 13.10%, a CAGR of 3.1% per year.

Response:

Confirmed.

d) Please confirm that Total Compensation per FTE for Non-Management is proposed to increase from 2013 Actual to 2017 Forecast by 12.38%, a CAGR of 2.9% per year.

Response:

Confirmed

e) Please provide the primary reasons why Management compensation is increasing at a more rapid rate than Non-Management compensation, and whether that difference is expected to continue into the future.

Response:

Part of the increases related to cost per FTE for Management is related the changes that have taken place in structure and succession planning. In 2013, Welland Hydro outsourced IT and eliminated a junior IT position. A clerical accounting position was replaced with a CPA to assist in the increased regulatory reporting and conversion to IFRS. A supervisor position in Customer Service has been replaced with an Engineer in 2017. Below is an analysis which breaks out the above changes to management positions:

2013 Actual				2017 Test				
$	FTE	$/FTE		$	FTE	$/FTE		%
$1,164,375	11	$105,852		$1,349,760	11	$122,705		15.92%
155,585	2.4	64,827		178,366	2	89,183		37.57%
$1,319,960	13.4	$98,504		$1,528,126	13	$117,548		19.33%

Both Management and Non-Management have had employees progress to base scale rates during the previous IRM period. Future increases for Management and Non-Management are expected to be more closely aligned going forward.

It is also important that management compensation is competitive with the broader market. Otherwise Welland Hydro risks losing much need talent to other LDCs such as Hydro One.

f) Please provide any benchmarking of the absolute levels of Management and Non-Management compensation or components of compensation that demonstrates that the rates of increase proposed by the Applicant are necessary either as "catch-up" or other adjustment to benchmark levels.

<u>Response</u>:

Welland Hydro identified on Page 11 of Revised Exhibit 4 that it had (7) Non-Management and (3) Management positions below full base pay rates in the 2013 COS Rate Application. An estimated increase related to pay progression for these employees of $119,000 per year was also identified on Page 11 of Revised Exhibit 4.

Non-Management:

The Table below identifies the job classifications of the (7) Non-Management positions identified as being below first class in the 2013 COS rate application. As stated previously, during union negotiations Welland Hydro benchmarks its non-management rates against other LDCs in the province with an emphasis on neighbouring LDCs. Welland Hydro has also acknowledged that the current contractual rates it pays to lineman are at the low end compared to other LDCs in the Niagara Region. For non-management positions at Welland Hydro, the largest hourly increase in pay between the lowest class and the first class takes place in the transition from second class to first class.

The increases associated with pay progression for non-management personnel from the 2013 COS to the 2017 COS are contractually related. Welland Hydro has four customer service representatives in the current collective agreement. Only one of four was in first class in 2013 leaving (3) below first class. Class progressions for the customer service representatives have resulted in approximately $24,000 in annual increases since the 2013 COS. In 2013 there were two (2) line staff below first class. One at 4th class and one at 5th class. The annual increase related to class progression for lineman from 2013 to 2017 is approximately $42,000. The billing clerk (1) was second class in 2013 and now first class which represents a class progression increase of approximately $11,000 per year. The GIS/CAD Operator (1) was 3rd class in 2013 and now first class in 2017 which represents approximately $19,000 in annual increase due to class progression. As a result, non-management positions represent $96,000 of the $119,000 identified as base pay class progression with the balance related to three management positions.

		Apr 1, 2013 Contract Hourly Rate	April 1, 2017 Contract Hourly Rate
		Customer Service Represtantive	Customer Service Represtantive
1st Class		28.67	31.35
2nd Class		23.62	25.83
3rd Class		21.68	23.71
4th Class		21.11	23.09
5th Class		18.37	20.08
6th Class			17.38
7th Class			16.13
		Lineman	Lineman
1st Class		36.83	40.42
2nd Class		31.59	34.69
3rd Class		30.62	33.63
4th Class		28.94	31.79
5th Class		26.36	28.96
		Billing Clerk	Billing Clerk
1st Class		31.36	34.29
2nd Class		25.78	28.19
3rd Class		24.89	27.22
4th Class		23.15	25.32
5th Class		21.33	23.33
6th Class		18.06	19.75
7th Class			19.17
		GIS/Cad Operator	GIS/Cad Operator
1st Class		36.99	40.96
2nd Class		29.93	33.13
3rd Class		27.71	30.67
4th Class		25.59	28.33
5th Class		22.18	24.56
6th Class		21.52	23.82

Management:

The three management positions below base level in the 2013 COS accounts for the balance in wage progression costs of $23,000 per year ($119,000-$96,000). The Billing Supervisor/MDMR Administrator and Billing Assistant were promoted from non-management positions during 2011 as a result of management retirements. In addition, the current Director of Engineering and Operations assumed his new position at the start of 2011. Management employees in new positions typically start at 80% of base pay and progress to 100% over the course of three to five years depending upon performance.

Not included in the above analysis are two changes made to management positions effective January 1, 2015. The first was the promotion of the Director of Finance into the newly created position as Chief Operating Officer & Director of Finance as part of succession planning. The second recognized the additional responsibilities added to the Customer Service & Conservation Manager when the Customer Service Supervisor position was eliminated. The total annual base increase associated with these two changes is approximately $30,000/year.

The benchmarking for all Management positons is outlined on Page 28 and 29 of Revised Exhibit 4. Management benchmarking is based on comparisons to other LDCs using the Annual Mearie Compensation Survey. On page 29 of Revised Exhibit 4, Welland Hydro estimated its total management compensation at 1.56% below the total for comparable positions with similar sized LDCs. Ranges of compensation vary from 11.6% above to 10.34% below average for comparable positions.

4.0-SEC-17

[Ex. 4, p. 22] Please provide the most recent report of the "external consultant" referred to in line 5, plus any prior report in the last two years that has recommended greater than normal increases to bring employees or groups of employees into line with expected levels.

Response:

The above reference was on page 22 of the original Exhibit 4 and is now page 28 of the Revised Exhibit 4 submitted on December 14, 2016.

The Hay Group system has been used by Welland Hydro since 2006 with a subsequent review performed by Crawford and Associates in 2012 ("external consultant"). The system establishes points for each position based on the evaluation of job duties and responsibilities. On an annual basis the Hay Group provides Welland Hydro with an update to the Hay Group All Industrial line formula – P50. Welland Hydro has adopted using the previous year's line formula in setting management compensation. For example, in 2015 the actual 2014 policy line formula was used to set management base level rates.

Below are the P50 policy lines for the 2014-2016 period provided by the Hay Group.

Welland Hydro-Electric System Corp.
Ontario Industrial data
2014 Recommended Policy Line
Line Formula - P50
$132.83 x Full Points + $23303

Welland Hydro-Electric System Corp.
Ontario Industrial data
2015 Recommended Policy Line
Line Formula - P50
$136.31 x Full Points + $24780

Welland Hydro-Electric System Corp.
Ontario Industrial data
2016 Recommended Policy Line
Line Formula - P50
$138.89 x Full Points + $25224

For each management position, pay is based on points inserted into the above formulas. Welland Hydro uses the results from these calculations to benchmark against information provided in the MEARIE Compensation Survey. The results of this benchmarking has been summarized on pages 28-29 of the Revised Exhibit 4 filed on December 14, 2016.

As indicated in Exhibit 4, a condition of participating in the survey is that Welland Hydro is obligated to keep the results confidential. However, Welland Hydro has approached MEARIE and has been given permission to release the 2016 Summary Report which has been filed with responses to interrogatories.

VECC – Exhibit 4

4.0-VECC-29
Reference: E4/pg.3

a) Please update the following Tables for the 2016 actual results

i. Table 4-1

Response:

Summary of OM&A Increases - 2013 Board Approved to 2017 Test Year

Expenses	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge	2016 Actual	2017 Test
Distribution Expenses - Operation	1,392,257	1,232,459	1,275,287	1,320,244	1,401,297	1,461,617	1,508,493
Distribution Expenses - Maintenance	1,621,552	1,653,693	1,651,437	1,834,314	1,854,122	1,815,064	1,884,210
Total Operation & Maintenance	**3,013,809**	**2,886,152**	**2,926,724**	**3,154,558**	**3,255,419**	**3,276,681**	**3,392,703**
Billing and Collecting	1,407,275	1,379,546	1,591,426	1,382,233	1,475,391	1,355,868	1,539,473
Community Relations	134,249	116,716	89,463	128,286	137,204	123,157	144,123
Administrative and General Expense	1,803,667	1,799,896	1,599,129	1,639,861	1,797,772	1,971,755	1,910,708
Total Administrative & Customer	**3,345,191**	**3,296,158**	**3,280,018**	**3,150,380**	**3,410,367**	**3,450,780**	**3,594,304**
Total OM&A Excluding Donations	**6,359,000**	**6,182,310**	**6,206,742**	**6,304,938**	**6,665,786**	**6,727,461**	**6,987,007**
Donations - Leap	11,000	11,150	11,250	11,500	11,750	11,500	12,900
Total Recoverable OM&A	**6,370,000**	**6,193,460**	**6,217,992**	**6,316,438**	**6,677,536**	**6,738,961**	**6,999,907**
Donations - Not In Rate Base	0	8,275	10,600	6,831	0	3,775	0
Total OM&A	**6,370,000**	**6,201,735**	**6,228,592**	**6,323,269**	**6,677,536**	**6,742,736**	**6,999,907**

ii. Appendix 2-JA

Response:

See Revised Table 2-JA below.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2016 Bridge Year	2017 Test Year
	Revised	Revised					
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 1,392,257	$ 1,232,459	$ 1,275,287	$ 1,320,244	$ 1,461,617	$ 1,401,297	$ 1,508,493
Maintenance	$ 1,621,552	$ 1,653,693	$ 1,651,437	$ 1,834,314	$ 1,815,064	$ 1,854,122	$ 1,884,210
SubTotal	**$ 3,013,809**	**$ 2,886,152**	**$ 2,926,724**	**$ 3,154,558**	**$ 3,276,681**	**$ 3,255,419**	**$ 3,392,703**
%Change (year over year)			1.4%	7.8%	3.9%	3.2%	4.2%
%Change (Test Year vs Last Rebasing Year - Actual)							17.6%
Billing and Collecting	$ 1,407,275	$ 1,379,546	$ 1,591,426	$ 1,382,233	$ 1,355,868	$ 1,475,391	$ 1,539,473
Community Relations	$ 134,249	$ 116,716	$ 89,463	$ 128,286	$ 123,157	$ 137,204	$ 144,123
Administrative and General	$ 1,814,667	$ 1,811,046	$ 1,610,379	$ 1,651,361	$ 1,983,255	$ 1,809,522	$ 1,923,608
SubTotal	**$ 3,356,191**	**$ 3,307,308**	**$ 3,291,268**	**$ 3,161,880**	**$ 3,462,280**	**$ 3,422,117**	**$ 3,607,204**
%Change (year over year)			-0.5%	-3.9%	9.5%	8.2%	5.4%
%Change (Test Year vs Last Rebasing Year - Actual)							9.1%
Total	**$ 6,370,000**	**$ 6,193,460**	**$ 6,217,992**	**$ 6,316,438**	**$ 6,738,961**	**$ 6,677,536**	**$ 6,999,907**
%Change (year over year)			0.4%	1.6%	6.7%	5.7%	4.8%

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2016 Bridge Year	2017 Test Year
Operations	$ 1,392,257	$ 1,232,459	$ 1,275,287	$ 1,320,244	$ 1,461,617	$ 1,401,297	$ 1,508,493
Maintenance	$ 1,621,552	$ 1,653,693	$ 1,651,437	$ 1,834,314	$ 1,815,064	$ 1,854,122	$ 1,884,210
Billing and Collecting	$ 1,407,275	$ 1,379,546	$ 1,591,426	$ 1,382,233	$ 1,355,868	$ 1,475,391	$ 1,539,473
Community Relations	$ 134,249	$ 116,716	$ 89,463	$ 128,286	$ 123,157	$ 137,204	$ 144,123
Administrative and General	$ 1,814,667	$ 1,811,046	$ 1,610,379	$ 1,651,361	$ 1,983,255	$ 1,809,522	$ 1,923,608
Total	**$ 6,370,000**	**$ 6,193,460**	**$ 6,217,992**	**$ 6,316,438**	**$ 6,738,961**	**$ 6,677,536**	**$ 6,999,907**
%Change (year over year)			0.4%	1.6%	6.7%	5.7%	4.8%

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	Variance 2013 BA – 2013 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs 2015 Actuals	2016 Bridge Year	Variance 2016 Bridge vs. 2015 Actuals	2017 Test Year	Variance 2017 Test vs. 2016 Bridge
Operations	$ 1,392,257	$ 1,232,459	$ 159,798	$ 1,275,287	$ 42,828	$ 1,320,244	$ 44,957	$ 1,461,617	$ 141,373	$ 1,401,297	$ 81,053	$ 1,508,493	$ 107,196
Maintenance	$ 1,621,552	$ 1,653,693	-$ 32,141	$ 1,651,437	-$ 2,256	$ 1,834,314	$ 182,877	$ 1,815,064	-$ 19,250	$ 1,854,122	$ 19,808	$ 1,884,210	$ 30,088
Billing and Collecting	$ 1,407,275	$ 1,379,546	$ 27,729	$ 1,591,426	$ 211,880	$ 1,382,233	-$ 209,193	$ 1,355,868	-$ 26,365	$ 1,475,391	$ 93,158	$ 1,539,473	$ 64,082
Community Relations	$ 134,249	$ 116,716	$ 17,533	$ 89,463	-$ 27,253	$ 128,286	$ 38,823	$ 123,157	-$ 5,129	$ 137,204	$ 8,918	$ 144,123	$ 6,919
Administrative and General	$ 1,814,667	$ 1,811,046	$ 3,621	$ 1,610,379	-$ 200,667	$ 1,651,361	$ 40,982	$ 1,983,255	$ 331,894	$ 1,809,522	$ 158,161	$ 1,923,608	$ 114,086
Total OM&A Expenses	$ 6,370,000	$ 6,193,460	$ 176,540	$ 6,217,992	$ 24,532	$ 6,316,438	$ 98,446	$ 6,738,961	$ 422,523	$ 6,677,536	$ 361,098	$ 6,999,907	$ 322,371
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)													
Total Recoverable OM&A Expenses	$ 6,370,000	$ 6,193,460	$ 176,540	$ 6,217,992	$ 24,532	$ 6,316,438	$ 98,446	$ 6,738,961		$ 6,677,536	$ 361,098	$ 6,999,907	$ 322,371
Variance from previous year				$ 24,532		$ 98,446		$ 422,523		$ 361,098		$ 322,371	
Percent change (year over year)				0%		2%		7%		6%		5%	
Percent Change: Test year vs. Most Current Actual						10.82%		3.87%					
Simple average of % variance for all years								13.02%					3.4%
Compound Annual Growth Rate for all years													2.5%
Compound Growth Rate (2015 Actuals vs. 2013 Actuals)								2.13%					

iii. Appendix 2-JB

Response:

See Revised Table 2-JB below.

Appendix 2-JB
Recoverable OM&A Cost Driver Table

	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2016 Bridge Year	2017 Test Year	Total Change
	Revised						
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	
OM&A Wages & Benefits	$ 3,854,709	$ 3,599,390	$ 3,520,394	$ 3,598,444	$ 3,598,444	$ 3,879,104	
OM&A Expenses	$ 2,515,291	$ 2,594,070	$ 2,697,598	$ 2,717,994	$ 2,717,994	$ 2,798,432	
OM&A Opening Balance	$ 6,370,000	$ 6,193,460	$ 6,217,992	$ 6,316,438	$ 6,316,438	$ 6,677,536	
Inflation/Class Changes & Other	-$ 24,038	$ 120,397	$ 148,182	$ 131,545	$ 129,084	$ 152,963	$ 526,588
2013 Additional Lineman - Part Year	-$ 46,907	$ 46,907	$ -	$ -			$ -
Vacant Lineman Partial Year	$ -	-$ 70,685	$ 70,685	$ -	$ -	$ -	$ -
Vacant CSR Partial Year	$ -	$ -	-$ 35,955	-$ 2,955	$ 35,955	$ -	$ -
Maternity Leave Billing Department	$ -	$ -	$ -	-$ 76,000	$ -	$ -	$ -
Maternity Leave Meter Shop	$ -	-$ 30,068	-$ 20,126	$ 50,194	$ 50,194	$ -	$ -
Outsourcing IT Labour to Expense	-$ 30,861	-$ 54,517	$ -	$ -	$ -	$ -	-$ 85,378
Customer Service Manpower Reduction	$ -	$ -	-$ 88,386	$ -	$ -	$ -	-$ 88,386
Capitalized Labour to Fixed Assets	-$ 20,411	$ 7,913	-$ 36,633	-$ 80,274	-$ 20,658	-$ 20,274	-$ 90,063
3rd Party Labour Billings Work Orders	-$ 8,414	-$ 52,885	$ 19,625	$ 15,535	$ 11,305	-$ 4,102	-$ 34,471
Overtime Charged to LDC Ice Storm	$ -	$ 18,427	-$ 18,427	$ -	$ -	$ -	$ -
CDM Labour Billings	-$ 36,912	-$ 67,808	$ 81,836	$ 5,566	$ 1,105	-$ 1,583	-$ 23,362
Streetlight Maintenance Billings Labour	-$ 30,857	-$ 7,077	-$ 4,999	$ 29,622	$ 26,692	$ 578	-$ 15,663
Sentinel Maintenance Billings Labour	-$ 7,544	-$ 2,216	$ 6,820	-$ 2,942	$ 3,014	$ 151	$ 225
Corporate Cost Allocation	-$ 3	-$ 606	-$ 2,389	-$ 888	$ 2,947	-$ 2,252	-$ 2,303
Accounting Assistant to Certified CA	-$ 14,321	-$ 65,683	$ 2,767	$ 97,421	$ 97,421	$ 6,736	$ 26,920
Garage Manpower Reduction	$ -	$ -	$ -	-$ 62,000	$ -	-$ 89,289	-$ 89,289
Electrical Engineer Reg Compliance	$ -	$ -	$ -	$ -	$ -	$ 121,797	$ 121,797
Post Retirmenet Benefit Costs	-$ 35,051	-$ 12,885	-$ 23,380	$ 3,541	$ 13,821	$ 5,603	-$ 51,892
Severance/Vacation Accrual	$ -	$ 91,790	-$ 21,570	-$ 70,220	-$ 70,220	$ -	$ -
Total Wages & Benefits Cost Drivers	**-$ 255,319**	**-$ 78,996**	**$ 78,050**	**$ 38,145**	**$ 280,660**	**$ 170,328**	**$ 194,723**
General Inflation/Exchange & Other	-$ 4,254	$ 15,620	$ 16,454	$ 169,959	$ 9,789	$ 44,053	$ 81,662
Smart Meter AMI - Exchange Rate	$ 2,399	$ 422	$ 7,280	$ 13,867	$ 3,168	$ 1,777	$ 15,046
Settlement Service Interval/Generation	-$ 314	$ 5,003	-$ 3,981	-$ 967	$ 1,480	$ 11,280	$ 13,468
Education & Training - Operations Staff	-$ 335	$ 9,486	$ 17,372	-$ 4,646	-$ 2,597	$ 780	$ 24,706
Contracted Tree Trimming Expense	$ 1,490	$ 48,670	-$ 47,649	$ 10,631	$ 9,590	$ 4,090	$ 16,191
Outsourcing IT Labour to Expense	$ 15,274	$ 4,901	-$ 781	-$ 620	-$ 394	$ 500	$ 19,500
Document Storage Software	$ 13,800	$ 23,633	$ 6,730	-$ 5,224	-$ 6,954	$ 700	$ 37,909
ODS Annual Maintenance	$ 2,463	$ 239	$ 543	-$ 99	$ 833	$ 1,456	$ 5,534
CIS/Home Connect/Financials Maintenar	-$ 8,016	-$ 30,306	$ 54,383	$ 14,631	$ 20,162	$ 12,499	$ 48,722
Financials - Annual Upgrade Support	$ -	$ 19,200	$ -	$ -	$ -	$ -	$ 19,200
Billing System Automation Platform	$ -	$ -	$ 10,250	$ 5,275	$ 4,750	$ 600	$ 15,600
Locates/Ontario One	$ 10,956	$ 15,983	$ 22,523	-$ 9,742	-$ 17,578	$ 17,579	$ 49,463
Regulatory Expenses	$ 43,345	-$ 73,611	$ 2,834	$ 128,355	$ 28,221	$ 54,429	$ 55,218
Bad Debt Expense	$ 1,971	$ 64,288	-$ 88,785	$ 24,756	$ 53,191	$ 2,300	$ 32,965
Obsolete Inventory Adjustment	$ -	$ -	$ 23,223	-$ 23,223	-$ 23,223	$ -	$ -
Total Expense Cost Drivers	**$ 78,779**	**$ 103,528**	**$ 20,396**	**$ 322,953**	**$ 80,438**	**$ 152,043**	**$ 435,184**
OM&A Wages & Benefits	$ 3,599,390	$ 3,520,394	$ 3,598,444	$ 3,636,589	$ 3,879,104	$ 4,049,432	
OM&A Expenses	$ 2,594,070	$ 2,697,598	$ 2,717,994	$ 3,040,947	$ 2,798,432	$ 2,950,475	
Closing Balance	$ 6,193,460	$ 6,217,992	$ 6,316,438	$ 6,677,536	$ 6,677,536	$ 6,999,907	

iv. Table 4-5 2-JL

Response:

See Revised Table 4-5 2-JL below.

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Actuals	2016 Bridge Year	2017 Test Year
	Revised	Revised					
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs							
O&M	$ 3,013,809	$ 2,886,152	$ 2,926,724	$ 3,154,558	$ 3,276,681	$ 3,255,419	$ 3,392,703
Admin Expenses	$ 3,356,191	$ 3,307,308	$ 3,291,268	$ 3,161,880	$ 3,462,280	$ 3,422,117	$ 3,607,204
Total Recoverable OM&A from Appendix 2-JB [5]	$ 6,370,000	$ 6,193,460	$ 6,217,992	$ 6,316,438	$ 6,738,961	$ 6,677,536	$ 6,999,907
Number of Customers [2,4]	22,298	22,139	22,381	22,564	22,752	22,768	22,974
Number of FTEs [3,4]	43.0	41.8	40.0	39.9	38.8	41.0	41.0
Customers/FTEs	518.56	529.64	559.53	565.51	586.39	555.32	560.34
OM&A cost per customer							
O&M per customer	135.16	130.37	130.77	139.80	144.02	142.98	147.68
Admin per customer	150.52	149.39	147.06	140.13	152.17	150.30	157.01
Total OM&A per customer	285.68	279.75	277.82	279.93	296.19	293.29	304.69
OM&A cost per FTE							
O&M per FTE	70,088.58	69,046.70	73,168.10	79,061.60	84,450.54	79,400.46	82,748.85
Admin per FTE	78,050.95	79,122.20	82,281.70	79,245.11	89,234.02	83,466.27	87,980.59
Total OM&A per FTE	148,139.53	148,168.90	155,449.80	158,306.72	173,684.56	162,866.73	170,729.44

v. Appendix 2-JC

Response:

See Revised Table 2-JC below.

Appendix 2-JC

OM&A Programs Table

Programs	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2016 Actuals	2017 Test Year	Variance (Test Year vs. 2016 Actuals)	Variance (Test Year vs. Last Rebasing Year (2013 Board-Approved)
	Revised	Revised							
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations & Maintenance									
Wages & Benefits	1,895,719	1,779,030	1,737,223	1,924,366	2,049,029	1,915,248	2,142,504	227,256	246,785
Smart Meter AMI Expense	75,493	77,892	78,314	85,594	88,762	99,461	90,539	-8,922	15,046
Vegetation Contracted Tree Trimming	134,186	135,676	183,346	136,697	146,287	147,328	150,377	3,049	16,191
Locates & Ontario One	67,353	78,309	94,292	116,815	99,237	107,373	116,816	9,443	49,463
General Supplies & Subcontracting	256,802	229,508	220,675	245,529	229,732	359,711	234,327	-125,384	-22,475
Education & Training	15,074	14,739	24,225	41,597	39,000	36,951	39,780	2,829	24,706
Insurance	58,330	72,712	78,307	61,560	77,280	77,663	78,825	1,162	20,495
Property Taxes	62,699	62,586	62,658	62,239	63,484	63,092	65,389	2,297	2,690
Telephone Charges	48,114	61,340	62,141	63,631	65,200	62,681	66,504	3,823	18,390
Stores Materials & Vehicle Maintenance	304,513	312,276	306,548	337,426	314,954	317,903	323,493	5,590	18,980
Other Expenses	95,526	62,084	78,995	79,104	82,454	89,270	84,149	-5,121	-11,377
Sub-Total Operations & Maintenance	**3,013,809**	**2,886,152**	**2,926,724**	**3,154,558**	**3,255,419**	**3,276,681**	**3,392,703**	**116,022**	**378,894**
Billing & Community Relations									
Wages & Benefits	889,036	861,117	939,334	847,440	879,208	720,065	922,909	202,844	33,873
Settlement Service Interval/Generation	61,812	61,498	66,501	62,520	64,000	61,553	75,280	13,727	13,468
Bad Debt Expense	84,335	86,306	150,594	61,809	115,000	86,565	117,300	30,735	32,965
Billing & Office Supplies	67,632	72,248	73,787	79,754	81,000	101,476	82,620	-18,856	14,988
ODS Annual Maintenance	32,322	34,785	35,024	35,567	36,400	35,486	37,856	2,370	5,534
Sync Operator/UCS Billing Analyst	50,493	50,498	53,571	54,136	56,100	56,332	58,344	2,012	7,851
Mobile Service Software (Mcare)	12,583	13,505	14,118	14,478	14,490	13,505	15,070	1,565	2,487
Billing System Automation Platform	0	0	0	10,250	15,000	15,525	15,600	75	15,600
Receivables Insurance	45,900	48,136	43,721	46,215	47,477	48,481	48,427	-54	2,527
Postage	134,466	122,473	139,881	134,725	139,900	149,988	142,698	-7,290	8,232
Other Expenses	162,945	145,696	164,358	163,625	164,020	190,049	167,492	-22,557	4,547
Sub-Total Billing & Community Relations	**1,541,524**	**1,496,262**	**1,680,889**	**1,510,519**	**1,612,595**	**1,479,025**	**1,683,596**	**204,571**	**142,072**
Administration									
Wages & Benefits	1,069,954	959,243	843,837	826,638	950,867	1,001,276	984,019	-17,257	-85,935
Outsourcing IT Labour to Expense	0	15,274	20,175	19,394	19,000	18,774	19,500	726	19,500
Document Storage Software	0	13,800	54,683	44,163	37,209	38,939	37,909	-1,030	37,909
CIS/Home Connect/Financials Maintenance	207,753	199,737	169,431	223,814	243,976	238,445	256,475	18,030	48,722
Financials Annual Upgrade Support	0	0	19,200	19,200	19,200	19,200	19,200	0	19,200
Regulatory Expenses	91,184	134,529	60,918	63,752	91,973	192,107	146,402	-45,705	55,218
Auditing & Legal	49,890	40,635	68,741	48,768	54,196	47,472	55,090	7,618	5,200
Outside Consulting Services	109,100	109,180	87,790	98,186	94,350	109,667	96,117	-13,550	-12,983
Conferences & Education	41,310	43,129	35,722	38,735	40,250	41,744	41,055	-689	-255
Board Director Fees Systems Corp.	45,669	50,096	46,502	61,767	60,956	58,209	65,890	7,681	20,221
Other Expenses	199,807	245,423	203,380	206,944	197,545	221,197	201,951	-19,246	2,144
Sub-Total Administration	**1,814,667**	**1,811,046**	**1,610,379**	**1,651,361**	**1,809,522**	**1,987,030**	**1,923,608**	**-63,422**	**108,941**
Total	**6,370,000**	**6,193,460**	**6,217,992**	**6,316,438**	**6,677,536**	**6,742,736**	**6,999,907**	**257,171**	**629,907**

vi. Table 4-9 (Appendix 2-K)

Response:

See Revised Table 4-9 2-K below.

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Actuals	2016 Bridge Year	2017 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	14.0	13.4	12.0	11.0	11.3	12.0	13.0
Non-Management (union and non-union)	29.0	28.4	28.0	28.9	27.5	29.0	28.0
Total	43.0	41.8	40.0	39.9	38.8	41.0	41.0
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 1,385,904	$ 1,319,960	$ 1,274,628	$ 1,271,074	$ 1,350,368	$ 1,394,578	$ 1,528,126
Non-Management (union and non-union)	$ 2,041,774	$ 2,012,339	$ 2,046,728	$ 2,103,125	$ 2,156,584	$ 2,228,264	$ 2,244,008
Total	$ 3,427,678	$ 3,332,299	$ 3,321,356	$ 3,374,199	$ 3,506,952	$ 3,622,842	$ 3,772,134
Total Benefits (Current + Accrued) [2]							
Management (including executive)	$ 336,525	$ 318,488	$ 297,639	$ 294,981	$ 305,903	$ 325,997	$ 360,666
Non-Management (union and non-union)	$ 566,574	$ 563,863	$ 560,433	$ 568,986	$ 563,518	$ 601,983	$ 610,229
Total	$ 903,099	$ 882,351	$ 858,072	$ 863,967	$ 869,421	$ 927,980	$ 970,895
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 1,722,429	$ 1,638,448	$ 1,572,267	$ 1,566,055	$ 1,656,271	$ 1,720,575	$ 1,888,792
Non-Management (union and non-union)	$ 2,608,348	$ 2,576,202	$ 2,607,161	$ 2,672,111	$ 2,720,102	$ 2,830,247	$ 2,854,237
Total Compensation Before OPEB & Unusual Items	$ 4,330,777	$ 4,214,650	$ 4,179,428	$ 4,238,166	$ 4,376,373	$ 4,550,822	$ 4,743,029
Retiree Benefits Premiums	$ 135,842	$ 100,791	$ 105,332	$ 102,368	$ 98,450	$ 108,730	$ 103,766
Retiree Benefits Accrual	$ 19,816	$ 19,816	$ 2,390	-$ 18,026	-$ 10,567	-$ 10,567	$ -
Unusal Items (Severance/Vacation Accrual)	$ -	$ -	$ 91,790	$ 70,222	$ -	$ -	$ -
Total Compensation	$ 4,486,435	$ 4,335,257	$ 4,378,940	$ 4,392,730	$ 4,464,256	$ 4,648,985	$ 4,846,795
Capitalized Wages & Benefits	-$ 428,587	-$ 448,998	-$ 441,085	-$ 477,718	-$ 557,992	-$ 498,376	-$ 518,650
CDM Billings Wages & Benefits	-$ 41,302	-$ 78,214	-$ 146,022	-$ 64,186	-$ 58,620	-$ 63,081	-$ 64,664
Third Party Billings Wages & Benefits	-$ 124,661	-$ 133,075	-$ 185,960	-$ 166,335	-$ 150,800	-$ 155,030	-$ 159,132
Associate Billings Wages & Benefits	-$ 37,176	-$ 75,580	-$ 85,479	-$ 86,047	-$ 60,255	-$ 53,394	-$ 54,917
Total Compensation OM&A	$ 3,854,709	$ 3,599,390	$ 3,520,394	$ 3,598,444	$ 3,636,589	$ 3,879,104	$ 4,049,432

4.0-VECC-30
Reference: E2/pg.21 Appendix 2-JC

a) Please provide the bad debt expense for years 2012 through 2017, showing the actual 2016 bad debt and explaining how the 2017 forecast cost is estimated.

Response:

	TOTAL
2012 Actual	$82,212
2013 Cost of Service	$84,335
2013 Actual	$86,306
2014 Actual	$150,594
2015 Actual	$61,809
2016 Actual	$86,565
2016 Bridge	$115,000
2017 Test	$117,300

The 2017 Test Year bad debt forecast was based on the three-year average actual from 2013 to 2015 of $99,570 plus anticipated increase of cost of power of just under 10% per year for two years.

4.0-VECC-31
Reference: E2/pg.26

a) What is the cost of the IT outsourcing which replaced the internal resource?

Response:

Table 4-7 on page 17 of Exhibit 4 shows Outsourcing IT costs at $19,500 in the 2017 Test Year.

4.0-VECC-32
Reference: E2/pg. 26/Table 4-9

a) The bottom of Table 4-9 includes a number of rows not normally included in the Board format Appendix 2-K. The first line– "Capitalized Labour" is self-explanatory, however the following items are not. Please explain the meaning/relevance of other three items ("CDM/Third Party/Associate Billings").

<u>Response</u>:

Table 4-9 provides total compensation costs including wages and benefits before distribution. These costs can be allocated to either OM&A, Capital, or Billable. Billable is composed of amounts charged to CDM funding, billed to Third Party for work performed, or Affiliate (Associate) companies for work performed. Welland Hydro added these additional rows to show how total compensation is allocated and as a reference to Table 4-4 which splits OM&A between Wages & Benefits versus non-wage benefit expenses.

b) Please also explain how Welland thinks the line titled Total Compensation OM&A should be compared year on year. For example, why is the 2013 actual figure for this line significantly lower than the Board approved amount?

<u>Response</u>:

Welland Hydro uses Table 4-9 to analyze changes from year to year and from the Board Approved 2013 COS to the 2017 COS. OM&A wages increased from $3,854,709 in the 2013 COS to $4,049,432 in the 2017. This is an increase of 5.1% over a four year period. A comparison of the 2013 COS to 2013 Actual shows a difference of 1.2 employees. As part of the 2013 COS settlement agreement, Welland Hydro was to add an apprentice lineman position. This did not occur until part way through 2013. As previously indicated Welland Hydro decided to outsource IT resulting in a reduction of one FTE part way through 2013. The accounting assistant made a decision to retire in late 2013 which was earlier than anticipated.

c) Please amend Table 4-13 to show 2012 actuals.

<u>Response</u>:

See Revised Table 4-13 below.

Department	2012 Actual	2013 Board Approve	2013 Actual	2014 Actual	2015 Actual	2016 Bridge	2017 Test	Change to 2013 COS
Operations & Maintenance								
Senior Management	1	1	1	1	1	1	1	0
Supervisory	2	2	2	2	2	2	2	0
Line Department	10	11	11	11	11	11	11	0
Engineer	0	0	0	0	0	0	1	1
Engineering	4	4	4	4	4	4	4	0
Engineering Summer Students	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0
Metering/Control Room	4	4	4	4	4	4	4	0
Vehicle Mechanics	2	2	2	2	2	2	1	-1
Store Keeper	1	1	1	1	1	1	1	0
Total Operations	24.7	25.7	25.7	25.7	25.7	25.7	25.7	0
Billing & Customer Service								
Senior Management	1	1	1	1	1	1	1	0
Supervisory	2	2	2	2	2	2	2	0
CDM/Billing Analyst	2	2	2	1	1	1	1	-1
Customer Service Representatives	4	4	4	4	4	4	4	0
Customer Service Summer Student	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0
Billing Clerk	1	1	1	1	1	1	1	0
Total Billing & Customer Service	10.3	10.3	10.3	9.3	9.3	9.3	9.3	-1
Administrative								
Senior Management	2	2	2	2	2	2	2	0
Administrative	1	1	1	1	1	1	1	0
Accounting	2	2	1	1	2	2	2	0
IT	1	1	0	0	0	0	0	-1
Accounts Payable	1	1	1	1	1	1	1	0
Total Administrative	7	7	5	5	6	6	6	-1
Total FTEs	42	43	41	40	41	41	41	-2

4-VECC-33
Reference: E4/pg.30

a) What was the percentage increase in compensation related to the one time adders for lineman in 2015?

<u>Response</u>:

Percentage Increase of Union Wages related to the one time adder for 2015 was 0.15%

b) Does Table 4-10 incorporate the one-time adders?

<u>Response</u>:

No but on Page 29 of Revised Exhibit 4 Welland Hydro identified the annual cost of the adder to be $4,200.

4.0-VECC-34
Reference: E4/pg.47

a) Please provide the EDA fees paid in each year 2012 through 2017 (forecast)

Response:

2012	$42,200
2013	$44,300
2014	$46,200
2015	$47,800
2016 Bridge	$48,300 (Actual $48,800)
2017 Test	$49,300

b) Please explain why the fees paid to the EDA increase from approximately 54k in 2013 to approximately 106k in 2014 and then back down to 54k again in 2015.

Response:

Please note that Table 4-19 is from the Accounts Payable System and may not reflect expenses in each year and would include HST. The current financial system cannot provide expenses per year by supplier. EDA generally bills in December for the following years fees. These bills are charged to a prepaid account and expensed the following year. Welland Hydro was previously holding these invoices for payment until the following year up to 2014 when payments began being made as per the terms of the invoice. This explains the two payments made in 2014 (2014 and 2015).

4.0-VECC-35
Reference: E4/pg. 47 Table 4-19

a) Please explain the spike in MEARIE Insurance fees in 2014.

Response:

Table 4-19 represent payments by year and not expense by year and is charged to a prepaid account and expensed on a monthly basis for the period covered by the insurance. Below is the MEARIE Insurance expense by year from 2013 Actual to 2017 Forecast showing the amounts paid to both MEARIE and Frank Cowan.

	MEARIE	Frank Cowan	TOTAL
2013	$51,033	$54,684	$105,717
2014	51,803	56,528	108,331
2015	38,287	57,116	94,403
2016 Actual	52,444	59,808	112,252
2016 Bridge	53,611	58,258	111,869
2017 Test	54,683	59,423	114,106
2017 Actual	53,716	64,111	117,827

Please note that in Table 4-19 payments made to MEARIE would also contain life insurance premiums for current and retired employees.

b) Please explain the significant increase in these fees since 2013

Response:

See response to a) above.

c) Please provide the 2016 actual fees and the 2017 expected fees.

Response:

See response to a) above.

d) Welland appears to have two insurance carriers MEARIE and Frank Cowan Insurance. Please explain the reason for two carriers.

Response:

MEARIE provides liability, director, privacy, network, and cybersecurity insurance. Cowan provides casualty, property, equipment, and auto insurance. Welland has had MEARIE quote on the insurance covered by Cowan in the past and costs were comparable but no change in insurance providers was made. Until recently Cowan was unable to provide some of the insurance covered by MEARIE. The plan is to have both companies quote on the total insurance package for the 2018 calendar year.

4.0-VECC-36
Reference: E4/pg.49

a) Welland states that it "*will use the deferred account approved by the OEB to capture increases in the 2016 Bridge Year*." Please provide the Board direction with respect to the establishment of the account for the revised OEB assessment costs.

Response:

Below is a section from the February 9, 2016 letter issued by the Board entitled: To Regulated Entities Subject to the OEB's Cost Assessment model.

New Variance Account

The OEB has established the following variance account for electricity distributors and transmitters to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model effective April 1, 2016:

- *Account 1508 Other Regulatory Assets, Sub-account OEB Cost Assessment Variance*
- Note: the offsetting entry to this account shall be to Account 5655, Regulatory Expenses.

b) Please provide the one-time application costs incurred to date.

Response:

	2016 Actual
Consultant/Legal	$53,892
Customer Engagement	$45,089
DSP Review	$12,700
Total	$111,681

Forecasted one-time application costs are expected to be higher than originally forecast.

c) Why has Welland included customer engagement costs under regulatory application one-time costs? Please provide any reference to Board direction for this treatment.

Response:

The RRFE Report outlined an "enhanced engagement between a distributor and its customers". The enhanced reporting requirements in a Cost of Service Application are outline in Chapter 2 Filing Requirements Cost of Service Rate Applications Section 2.16

dated July 14, 2016 and a presentation from the Ontario Energy Board entitled Giving Energy Consumers a stronger voice in OEB Adjudicative Process dated May 13, 2016. Welland Hydro considers these to be “one time” costs associated with a COS Rate Application as they are enhancements to previous Cost of Service Applications and are not included in current distribution rates.

4.0-VECC-37
Reference: E4/pg.56-58

a) Please confirm that Welland has 3 asset classes in which it has chosen useful life outside the Kinectrics TUL range as shown in Table 4-25: 1820 Distribution Stations both <>50kV and 1845 UG Conductors. Are the Battery Bank/Chargers common to both < and > 50 kV stations?

<u>Response</u>:

Confirmed, there are currently three asset classes where useful life is outside the Kinectrics TUL range. All of Welland Hydro's substations are less than 50kV.

b) What studies has Welland undertaken to support the revised TUL.

<u>Response</u>:

Welland adopted these useful lives in 2012 and were subsequently used in the 2013 COS Rate Application. Welland Hydro engaged KPMG to facilitate the process of developing revised useful lives in 2012 which included internal accounting and engineering staff. There are no formal studies available to support the revised TUL.

4.0-VECC-38
Reference: E4/pg.65

a) Please update Table 4-31 to reflect 2016 actual PILs.

Response:

See revised Table 4-31 below showing 2016 actual PILs.

Item	2013 COS	2013 Actuals	2014 Actuals	2015 Actuals	2016 Bridge Year	2016 Actuals	2017 Test Year
Taxable Income Before Loss Carryforwa	333,563	-33,903	-267,760	724,249	-139,419	142,615	354,979
Charitable Donations Carryforward Used				-15,596			
Non Capital Loss Carryforward Used				-16,633			
Taxable Income	333,563	-33,903	-267,760	692,020	-139,419	142,615	354,979
Effective Tax Rate	19.5%	19.5%	26.5%	26.6%	26.5%	26.5%	26.5%
PILS before Apprentice Tax Credit	65,045	0	0	184,016	-36,946	37,793	94,069
Apprentice Tax Credits	-22,000	-11,397	-23,129	-26,521	-20,000	-20,000	-20,000
PILS before Gross Up	43,045						74,069
Grossed Up PILS/PILS Payable	53,472	-11,397	-23,129	157,495	-56,946	17,793	100,775
Taxable Losses Applied to Other Years							
2010 Year		-33,903					
2011 Year			-251,127				
2015 Year			-16,633				
2016 Year							
Available to Offset Future Taxable Loss		0	0	692,020	-139,419	692,020	692,020

b) Please explain the tax rule change that excluded Welland from the Small Business Tax Deduction.

Response:

A detailed explanation is included in Welland Hydro's 2016 IRM Rate Application EB-2015-0109 in which the OEB approved a tax change rate rider until the next Cost of Service Rate Application. In summary, both the Federal and Ontario Small Business Tax deductions are now subject to Taxable Capital limits which Welland Hydro exceeds.

4.0-VECC-39
Reference: E4/pg.66

a) Welland proposes to amortize the tax carry forward loss of $139,419 over the term of the rate plan. Is Welland aware of any precedent supporting this treatment?

<u>Response</u>:

Welland Hydro is not aware of any precedent supporting this treatment although it may have been dealt with in Grimsby EB-2015-0072. Welland Hydro is also not aware of any process to allow for the adjustment for the elimination of loss carry forwards included in COS rates during a subsequent IRM rate setting process. Welland Hydro filed application EB-2007-0663 in 2007 to correct where a loss carryforward for tax purposes in the 2006 COS was not adjusted in the 2007 IRM. However, as indicated in the response to 4.0-VECC 38 above Welland Hydro's actual taxable income for 2016 is positive and as a result there is no actual taxable loss carryforward into the 2017 test year. It is Welland Hydro's understanding that actual PILS data for the bridge year must be used (as opposed to forecast) when it is available as per the decision in Grimsby's COS Application EB-2015-0072.

b) Table 4-32 does not appear to show any adjustment in 2017 for the amortized carry forward loss. Please explain how this adjustment is made.

<u>Response</u>:

Correct, there was no adjustment made in the 2017 Test Year to reflect the forecasted taxable loss carryforward from the 2016 Bridge Year. Should a taxable loss carryforward been available (for a one year period only as was the case anticipated in the original application), Welland Hydro is of the view that only 20% of the loss carryforward should be reflected in 2017 COS rate unless a process was agreed to on how the elimination of the loss carryforward at the end of 2017 would be dealt with in the 2018 IRM rate application. However, as indicated above, Welland Hydro does not have an actual taxable loss carryforward at the end of 2016.

4.0-VECC-40
Reference: E4/pg.70

a) What are Welland's 2016 property tax assessments? Has the 2017 mill rate ben announced for 2017. If so what is the estimated 2017 property tax based on 2016 increased by the 2017 announced mill rate.

<u>Response</u>:

Below is a table showing the 2016 actual assessments, mill rates, and total property tax for Welland Hydro.

		ASSESSMENTS		TAX RATE	ENTITLEMENT					REGION ENTITLEMENT	CITY ENTITLEMENT	
WELLAND HYDRO	CH	1,508,500	x	0.03674386	55,428.11	x	UTS / TTC	3799590 / 11889993	0.31956	17,712.72	37,715.39	55,428.11
	IH	257,600	x	0.05230374	13,473.44	x	UTS / TTC	617,008 / 1,837,786	0.33573	4,523.50	8,949.94	13,473.44
	RH	30,700	x	0.01606393	493.16	x	UTS / TTC	23,666,538 / 56,939,568	0.41564	204.98	288.18	493.16
	CK	38,500	x	0.02572070	990.25	x	UTS / TTC	145977 / 456805	0.31956	316.45	673.80	990.25
		1,835,300			70,384.96					22,757.64	47,627.32	70,384.96

The City of Welland's web site does not show mill rates for the 2017 tax year. However, budget increases at the region and city are expected to increase tax bills by 5% in 2017. Welland Hydro has included a 3% increase in the 2017 test year.

4.0 -VECC -41
Reference: Exhibit 4, LRAMVA Work Form

a) The LRAMVA Work Form (2011-2014 LRAM Tab) does not appear to include any persisting results in 2012 from 2011 CDM programs. Please review and reconcile.

Response:

WHESC is not seeking the recovery of LRAMVA for results from 2011 and 2012 programs that occurred in 2011 and 2012. WHESC is only seeking recovery for results that occurred in 2013 and onward since this was the previous cost of service year in which the current LRAMVA threshold was set. The current LRAMVA threshold represents 2011 programs that persist into 2013, 2012 programs that persist into 2013 and 2013 programs.

b) The LRAMVA Work Form (2011-2014 LRAM Tab) values do not all reconcile with those reported in the IESO Report (Appendix 4-H). For example, the reported savings for 2011 from pre-2011 programs is 92,719 in the LRAMVA Work Form versus 928,364 kWh in the IESO Report. Please review and correct the inputs to the LRAMVA model as needed.

Response:

The derivation of 92,719 shown in the LRAMVA Work Form and how it relates to 927,188 kWh in the IESO Report is provided in response to 4-Staff-56 d). Only 10% of the 927,188 is assigned to the GS < 50 kW class and the remaining 90% is assigned to the GS > 50 kW class but 90% of the kW value is used. The difference between 928,364 and 927,188 is 1,176 kWh which represent the kWh associated with Pre-2011 Programs Completed in 2011 for High Performance New Construction. The savings for this program are assigned to the GS > 50 kW class but there are no kW associated with the 1,176 kWh. As a result, the Pre-2011 Programs Completed in 2011 for High Performance New Construction results are not included in the analysis.

Exhibit 5 – Cost of Capital and Capital Structure

Board Staff – Exhibit 5

5-Staff-57
Ref: OEB Letter - Cost of Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications, October 27, 2016

On October 27, 2016, the OEB issued its updated cost of capital parameters for 2017 rate applications. The updated parameters are as follows:

Cost of Capital Parameter	Value for Applications for rate changes in 2017
ROE	8.78%
Deemed LT Debt Rate	3.72%
Deemed ST Debt Rate	1.76%

Please update all applicable models for the updated cost of capital parameters in accordance with IR 6-Staff-58.

Response:

Welland Hydro submitted revised 2017 Revenue Requirement Workform and 2017 Bill Impacts on December 21, 2016 with the updated 2017 Cost of Capital parameters. Welland Hydro has filed revised models with changes made as a result of the interrogatory process.

<u>VECC – Exhibit 5</u>

5.0-VECC-42
Reference: E5

a) When did the $3.7 million TD debt come due?

<u>Response</u>:

February 1, 2014

b) Why did Welland not replace this debt?

<u>Response</u>:

Welland Hydro had no forecasted requirements for additional long term debt at the time.

Exhibit 6 – Calculation of Revenue Deficiency

Board Staff – Exhibit 6

6-Staff-58

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

Also upon completing all interrogatories from OEB staff and intervenors please provide any updates to the following Microsoft Excel documents in working format:

- **PILS spreadsheet**
- **any Appendix 2 changes (e.g. cost allocation, rate design, and bill impacts, and so on as required)**
- **EDDVAR spreadsheet, and the updated cost allocation model (as per the interrogatory below) reflecting the revised revenue requirement in the updated RRWF**
- **LRAM Workform**

Response:

Welland has filed revised PILS spreadsheet, Chapter 2 Appendices, EDDVAR, LRAM, and other models in response to interrogatories.

Exhibit 7 – Cost Allocation

Board Staff – Exhibit 7

7-Staff-59
Weighting Factors Ref: Ex.7, Pages 3-4

As instructed by the OEB, Welland Hydro has used LDC specific weighting factors.

a) Was a cost study conducted to determine the weighting factors for services and billing and collecting? Please describe how the weighting factorsdetermined.

Response:

The weighting factors for services and billing and collecting are consistent with the factors used in the 2013 cost allocation study. At that time, a cost study was not conducted to determine the weighting factors but was based on discussions with billing and collection staff that were knowledgeable in this area.

b) With respect to the General Service>50kW rate classes, what was the methodology used to determine the weighting factors?

Response:

See response to a) above. The capital costs associated with the GS>50kW class is based on actual. Meter reading costs were based on analysis relating to account 5310 and settlement services costs which are directly related to the GS>50kW class.

c) With respect to the Street Lighting and Sentinel Load classes, Welland Hydro notes that, for the most part, its subsidiary (Welland Hydro Electric Holding Corp. which is 100% owned by the City of Welland) performs streetlight and sentinel light maintenance on behalf of Welland Hydro. Please explain why aweighting factor of zero was not used. If any changes are necessary, please make the necessary corrections.

Response:

The weighting factors are not related to the cost of maintaining the street lights and sentinel lights. As a result, the process used to maintain the lights will not impact on the weighting factors and cause them to be set to zero. All expenses related to street and sentinel lights are charged (included in billings to associates) to Welland Hydro Energy Services and are not included in Welland Hydro-Electric System's OM&A costs.

7-Staff-60
Ref: Ex. 7, Table 7-7 Revenue to Cost Ratios, Page 7

Rate Class	2013 Board Approved	2017 Updated Cost Allocation Study	2017 Proposed Ratios	2018 & 2019 Proposed Ratios	Board Targets Min to Max	
Residential	106.5%	104.8%	104.8%	104.8%	85.0%	115.0%
General Service < 50 kW	96.1%	95.8%	95.8%	95.8%	80.0%	120.0%
General Service > 50 kW	80.0%	76.8%	84.7%	84.7%	80.0%	120.0%
Street Lights	89.3%	367.7%	120.0%	120.0%	80.0%	120.0%
Sentinel Lights	106.5%	67.7%	84.7%	84.7%	80.0%	120.0%
Unmetered Scattered Load	106.5%	146.7%	120.0%	120.0%	80.0%	120.0%

Please explain why the revenue-to-cost ratio for the street lighting rate class has increased significantly as indicated by the 2017 cost allocation study.

<u>Response</u>:

The revenue-to-cost ratio for the street lighting rate class has increased significantly since the Board changed the policy on how costs are allocated to the Street Lighting class. The Board policy changed after the last cost allocation study was conducted in 2013. Please refer to the letter from the Board dated June 12, 2015 on the subject of Issuance of New Cost Allocation Policy for Street Lighting Rate Class.

7-Staff-61
Proposed microFIT Rate
Ref: Ex. 7, Page 8

Welland Hydro notes that the monthly charge from Welland Hydro's service provider to supply hourly generation data for the IESO monthly invoice is $10.00 per month.

Welland Hydro is proposing to increase the microFIT charge from $5.40 to $11.25. The calculation is shown below:

Monthly Service Provider Costs	**$10.00**
Standard Supply Service – Administration Charge	**$0.25**
Postage/Cheque and Banking	**$1.00**
Total	**$11.25**

a) Please confirm if Welland Hydro has provided for this increase in revenue in its 2017 revenue offsets. If not, please make the applicable corrections.

Response:

Welland Hydro has accounted for the increase in revenue offsets as can be seen in Table 3-37 Other Revenue in Exhibit 3 Page 32.

b) How many customers would be impacted by this change?

Response:

A total of 80 microfit accounts would be impacted by the change.

c) How much revenue would the change in the microFIT rate equate to on an annual basis?

Response:

The change in the microFIT charge results in an annual increase of $5,616.

OEB staff notes that an increase in the microFIT rate to $10.00 has been approved by the OEB in some recent cost of service proceedings, however other applicants have not included the additional $1.25 for Standard Supply Service and Postage.

d) Please provide supporting rationale for including this additional charge.

Response:

Welland Hydro's goal is to apportion actual costs to the appropriate customer class. The methodology in this case was to cover at least variable costs. The $10.00 charge would cover only the cost of the outside service provider.

7-Staff-62
Elimination of Large Use Rate Class
Ref 1: Ex. 7, Page 8
Ref 2: Ex. 2. Distribution System Plan, Page 5

At reference 1, Welland Hydro notes that it is proposing to eliminate its Large Use rate class since there are no longer any customers in that class since 2014. At reference 2, Welland Hydro notes that recently, General Electric announced a major investment of $165 million U.S. in a state of the art "brilliant" manufacturing facility in the City of Welland which is scheduled for completion in 2018.

a) Please confirm that the new General Electric facility will not be a Large Use customer.

Response:

Initial discussions between Welland Hydro and General Electric and its contractors/consultants confirm the new facility will not be a Large Use customer.

b) If the answer to (a) is no, please explain Welland Hydro's proposal to eliminate its Large Use rate class.

Response:

Not applicable.

c) Please provide the dollar impact of the loss of Welland Hydro's Large Use customer.

Response:

The dollar impact of the loss of Welland Hydro's Large Use customer is $98,400 per year as shown in Table 6-5 in Exhibit 6 page 9.

d) Please confirm that Welland Hydro does not anticipate any Large Use customers to enter in its service territory for the forecast period.

Response:

Welland Hydro is unaware of any potential Large Use customers for the 2017 Test Year and the 2018-2021 IRM period.

SEC – Exhibit 7

7.0-SEC-18

[Ex. 7, p. 6] Please provide a side by side table showing the costs allocated to the GS>50 class in the 2013 Board approved Cost Allocation Study, and the costs allocated in the Application, with an explanation of each of the major changes in allocated amounts.

Response:

The following provides a side by side table showing the total costs and the costs allocated to the General Service >50 class in the 2013 Board approved Cost Allocation Study, and the costs allocated in the Application.

	Total			GS > 50 kW		
Expenses	**2013**	**2017**	**% Difference**	**2013**	**2017**	**% Difference**
Distribution Costs	$2,590,800	$ 2,995,390	16%	$ 603,006	$ 682,107	13%
Customer Related Costs	$1,320,692	$ 1,936,786	47%	$ 96,152	$ 89,747	-7%
General and Administration	$1,911,934	$ 2,067,731	8%	$ 342,120	$ 323,897	-5%
Depreciation and Amortization	$ 874,188	$ 1,429,600	64%	$ 227,692	$ 317,221	39%
PILs	$ 50,631	$ 100,775	99%	$ 13,020	$ 24,512	88%
Interest	$ 654,849	$ 874,137	33%	$ 168,399	$ 212,623	26%
Total Expenses	$7,403,095	$ 9,404,419	27%	$1,450,389	$1,650,106	14%
Direct Allocation	$ 856,800	$ -	-100%	$ 91,085	$ -	-100%
Allocated Net Income	$1,030,145	$ 1,231,915	20%	$ 264,908	$ 299,648	13%
Revenue Requirement	$9,290,040	$10,636,334	14%	$1,806,382	$1,949,754	8%

In all cost categories, the % Difference for the General Service >50 class between 2013 and 2017 is less than the % Difference in total costs before the costs are allocated to each rate class. This suggests that the General Service > 50 kW class are being allocated less of the total cost in 2017 than in 2013.

The two main drivers in the cost allocation model are number of customers/connections and demand. The following shows the number customers/connections for 2013 Board Approved and 2017 from the Application.

Customers/Connections	2013	2017	% Difference
Residential	20,432	21,042	3%
General Service < 50 kW	1,696	1,783	5%
General Service > 50 kW	169	149	-12%
Streetlights	3,056	3,658	20%
Sentinel Lights	574	515	-10%
Unmetered Loads	225	257	14%
Total	26,152	27,404	5%

Demand is directly related to the volume forecast. The following shows the comparison of volume between 2013 Board Approved and 2017 from the Application. In both cases the Large User class is not shown since in 2013 all costs for the Large User class were directly allocated to the class in the cost allocation model and the number of customers and demand was set to zero in order to not allocate any other costs to the Large User class. In 2017, the Large User class has been eliminated.

Volume	2013	2017	% Difference
Residential	162,565,618	161,051,510	-1%
General Service < 50 kW	54,784,534	54,658,680	0%
General Service > 50 kW	141,530,394	128,665,764	-9%
Streetlights	1,273,281	1,282,067	1%
Sentinel Lights	831,977	753,964	-9%
Unmetered Loads	1,111,230	944,313	-15%
Total	362,097,034	347,356,298	-4%

For the General Service > 50 kW the number of customer and the volume is less in 2017 which is causing the allocated cost to General Service > 50 kW to be less as a proportion of the total costs for all categories of costs.

7.0 – VECC –43
Reference: Exhibit 7, page 4 (lines 10-14)

a) It is noted that in the CA Model the total cost for Meter Reading (Account 5310) are $26,088. Please reconcile this values with $34,545, the sum of values quoted at lines 10-14

Response:

The $21,489 associated with labor and vehicle costs related to metering costs was incorrectly stated on Page 4 of Exhibit 7. The breakdown to the $26,088 is as follows:

5310 Labour and Vehicle Costs	$13,032
5310 Phone Line Charges	$5,712
2310 Metering TS Station	$7,344
TOTAL	$26,088

b) Please explain why the cost of meter monitoring at the TS is included in Account 5310 as opposed to in one of the Transformer Station Equipment Accounts (e.g. #4820).

Response:

These costs would have to be recovered in variances if they were charged to account 4820. Welland Hydro believes they are better suited to OM&A costs than variance accounts as they are related to metering the volumes that are billed to Welland Hydro from the IESO for electricity volumes.

7.0 – VECC –44
Reference: Exhibit 7, page 8 (lines 12-24)
Cost Allocation Model, Tab O3.6

a) Please confirm that the $10 charge from the Service Provider is just for providing hourly generation data – the equivalent of meter reading.

Response:

The charge covers more than the hourly reading of both fit and microfit generation. A report is also provided which details the information necessary for Welland Hydro to fill out the 1598 IESO monthly true up related to generation from within Welland Hydro's service territory. Generation on an hourly basis, equivalent hourly HOEP pricing, and contract pricing paid to generators (varies by contract) is required to produce such a report. Manually producing such a report would be extremely labour intense.

b) It is noted that the Welland-specific microFIT charge from Tab O3.6 would be $5.16 inclusive of $0.01 in meter reading expense. Why would it not be appropriate to charge microFIT customer for the other of elements of the microFIT charge set out in Tab O3.6 such as meter maintenance?

Response:

MicroFIT customers are required to pay for the costs of the meter and installation and as such are not in capital meter costs (offset by contributed capital). Welland Hydro believes it is requesting to charge microFIT customers the appropriate monthly service charge in this application which is higher than the current Board set rate.

c) Does the proposed cost of $1.00 adequately cover the full cost of preparing and issuing a bill?

Response:

The $1.00 portion of the total charge is to cover processing of the cheque and postage. The majority of the charge is to cover postage as a high percentage of microFit contract owners have chosen not convert to direct deposit. As indicated above in response to Board Staff 7-61 Welland Hydro is seeking to recover variable costs.

d) Why is it appropriate to include the $0.25 SSS Administrative Charge?

Response:

Welland Hydro charges this amount to all other customer classes and believes a similar amount should be charged to the microFIT customer class.

Exhibit 8 – Rate Design

Board Staff – Exhibit 8

8-Staff-63
Interval v. Non-Interval RTSR
Ref: Ex.8, Section 2.8.3, Page 8

Welland Hydro has completed the RTSR Workform with the view of eliminating the interval versus non-interval classifications in the GS>50kW rate class in preparation with the OEB directive to eliminate all non-interval meters before 2019.

a) Please confirm that Welland Hydro is referring to the May 21, 2014 Notice of Amendment to a Code regarding revisions to the Distribution System Code to require a distributor to install an interval meter (i.e., a "MIST meter") on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW.

Response:

Confirmed, Welland Hydro was referring to the May 21, 2014 Notice of Amendment regarding revisions to the Distribution System Code concerning installation of interval meters for all customers over 50kW peak demand.

b) What is the status of Welland Hydro's installation of MIST meters?

Response:

Welland Hydro has budgeted $60,000 per year from 2018 to 2019 to convert existing non-MIST meters currently on GS>50 kW customers. See Exhibit 2 Page 47.

c) Please confirm that Welland Hydro is installing MIST meters for all new customers in the GS>50kW rate classification.

Response:

Confirmed, Welland Hydro is installing MIST meters for all new customers in the GS>50 kW rate classification.

d) Please confirm that Welland Hydro currently does not have any non-interval metered customers in its GS>50 rate class.

Response:

See response to (b). Welland Hydro currently has approximately 120 customers with non-interval meters.

e) If the answer to (c) is no, please explain how Welland Hydro plans to charge these customers come May 1, 2017.

Response:

Welland Hydro will continue to read the demand kW manually on a monthly basis. These customers (depending on classification) will continue to be billed Weighted Average Price (WAP) or RPP until MIST meters have been installed.

8-Staff-64
Specific Service Charges
Ref: Ex.8, Section 2.8.6, Page 9

Welland Hydro proposes two new Specific Service Charges. Currently, Welland Hydro hand delivers a final disconnection notice and provides the customer with the option of making a payment to avoid disconnection. Currently, there is no charge for this service. Welland Hydro notes that these charges are in effect at many LDCs in Ontario.

Specific Service	**Unit**	**Charge**
Collection of account charge – no disconnection – during regular hours	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00

a) **Has Welland Hydro notified its customers of the proposed new charges?**

Response:

The addition of the two new charges was included in the Ontario Energy Board Notice to Customer of Welland Hydro Electric System Corp. which was published in both English and French local newspapers.

i. **If not, please explain why.**

Response:

Not applicable.

b) **Have the anticipated dollars for the 2017 test year associated with these two new charges been included in Welland Hydro's proposed other revenue? If not, please make the necessary updates.**

Response:

Welland Hydro does not currently perform collection calls outside of regular hours from Monday to Friday. This would limit anticipated revenue to collection of account charge during regular business hours. Welland Hydro did not include any new additional revenue related to the two new charges in its original application. Welland Hydro is unsure of the revenue to include for the new charge as customers may choose other payment arrangements to avoid the new charge. In addition, the new winter disconnection rules prohibit charging any collection of account charges for extended periods of time.

<u>SEC – Exhibit 8</u>

8.0-SEC-19

[Ex. 8, p. 5] Please confirm that,

a) If the GS>50 fixed monthly charge is set at the Minimum System with PLCC, $69.59, the variable charge would be $4.3394/kW.

<u>Response</u>:

Confirmed

b) If the GS>50 fixed monthly charge is set at the current level, $281.42, the variable charge would be $3.2953/kW.

<u>Response</u>:

Confirmed

8.0-SEC-20

Please confirm that the Applicant serves 35 school accounts. Please advise how many school accounts are in each of GS<50 and GS>50.

<u>Response</u>:

Welland Hydro believes the total accounts associated with school boards including portables and temporary services is currently 40. The break down between GS<50 and GS>50 is as follows:

GS<50-31

GS>50-9

<u>VECC – Exhibit 8</u>

8.0 –VECC – 45
Reference: Exhibit 8, page 9

a) Are customers charged if the disconnection notice is delivered and no payment is collected?

<u>Response</u>:

Welland Hydro currently does not charge for a disconnection notice as it is not in the current tariff of rates and charges. It is anticipated that Welland Hydro would invoice the collection charge if a payment is made. If no payment is made and a disconnection is required, a reconnection fee would be invoiced upon reconnection. Welland Hydro would not charge both fees for the same visit to the customer.

b) What is the basis for the $30 and $165 proposed values?

<u>Response</u>:

Comparison to charges included in the tariff of rates and charges for other LDC's in the province of Ontario

c) When would Welland deliver a Final Disconnection Notice after regular hours?

<u>Response</u>:

Welland Hydro does not currently issue disconnection notices after regular hours or on weekends. Plans are to continue to issue disconnection notice during regular hours from Monday to Friday.

d) If the decision as to time of delivery is at Welland's discretion, why should the customer be charged extra for delivery after regular hours?

<u>Response</u>:

As stated above Welland Hydro does not currently or plan to issue disconnection notices outside of regular hours from Monday to Friday.

8.0 –VECC – 46
Reference: Exhibit 8, page 12

a) Why were bills with usage below 50 kWh per month excluded?

<u>Response</u>:

Welland Hydro used this methodology in its 2016 IRM Rate Application as per EB-2012-0410.

b) What would be the 10% percentile usage value be if all customers with 12 monthly bills were included?

<u>Response</u>:

The 10% percentile for customers with 12 monthly bills is 302 kWh which compares to 308 when excluding customers below 50 kWh per month.

Exhibit 9 – Deferral and Variance Accounts

Board Staff – Exhibit 9

9-Staff-65
Ref: Exhibit 9, Page 6, DVA Continuity Schedule

Account 1595 (2013) has not been requested for disposition in this application. Welland Hydro indicated that the related DVA rate riders were to be disposed over a two year period, from May 2013 to April 2015 and the stranded meter rate rider was to be disposed over a four year period, from May 2013 to April 2017. Welland Hydro proposes to bring forward any residual amounts for disposition in its 2019 IRM rate application.

Per July 2012 APH FAQ# 10, "Account 1555 should be used for purposes of both the disposition and the recovery of stranded meter costs (i.e., the disposition of approved costs should not be transferred to the sub-accounts of Account 1595)". Therefore,

a) Please revise the DVA continuity schedule to separate out transactions relating to stranded meters in Account 1555, sub-account Stranded Meter Costs.

Response:

Revised DVA continuity schedules have been submitted with responses to interrogatories to reflect Account 1555 stranded meter costs.

b) Please also revise the DVA continuity schedule to reflect Account 1595 (2013) excluding any stranded meter transactions.

Response:

Revised DVA continuity schedules have been submitted with responses to interrogatories to reflect revised Account 1595 (2013).

i. Please indicate if Welland Hydro is requesting Account 1595 (2013) for disposition in this application. If not, please explain why not.

Response:

Revised DVA continuity schedules have been submitted to reflect the request to dispose of revised balances in Account 1595 (2013).

9-Staff-66
Ref: Exhibit 9, Page 13, Table 9-5

Table 9-5, 2013 includes ($45k). From Welland Hydro's 2013 settlement agreement, Welland Hydro disposed of $46k for IFRS costs recorded in Account 1508 as at December 31, 2011. Please confirm that Welland Hydro had not included any further IFRS costs that qualified to be recorded in this sub-account in its 2013 revenue requirement. If this is not the case, please revise Table 9-5 to remove these particular costs that Welland Hydro would have previously received recovery for.

Response:

Welland Hydro can confirm that it has not included any amounts recovered in the 2013 settlement agreement for recovery in this rate application and as a result no changes are required to Table 9-5 in Exhibit 9.

9-Staff-67
Ref: Exhibit 9, Page 16

Welland Hydro indicated that it does not follow Article 490 of the APH and does not track variances in Account 1518 RCVA Retail and Account 1548 RCVA STR as it believes the variances would not be material.

a) Would Welland Hydro be able to provide estimates of the variances in the above noted accounts? If yes, please provide the amount.

Response:

There is currently no additional work involved in billing a customer if they are with a retailer. In other words, a billing batch would include retailer and non-retailer accounts. It is not practical to break out software maintenance costs between retailer and non-retailer accounts. However, there are variable costs associated with retailer accounts provided by an EBT service provider. For 2015, cost of the EBT service provider was $8,418. Revenue from Account 4082 and 4084 totals $17,448 in 2015 which indicates that variable costs are being recovered. The difference in revenue over variable costs contributes to the annual maintenance cost of CIS software.

b) Is Welland Hydro requesting the OEB's approval not to track variances in these accounts going forward?

Response:

Yes, on the basis that there are no additional labour costs relating to billing retail customers and separating maintenance costs for the CIS is not practical.

9-Staff-68
Ref: Exhibit 9, Page 18

In allocating Account 1589, 2015 billed Non-RPP kWh was used for Residential and GS<50kW customer classes. For the GS>50kW and Sentinel Light Customer Classes, Welland Hydro used the ratio of Non-RPP to RPP 2015 billed kWh applied to the 2017 forecasted kWh. For the 2017 forecast, please explain why there is a mixture of approaches used (i.e. 2015 billed kWh used for Residential and GS<50kW and 2017 forecast kWh used for GS>50kW and Sentinel Light customer classes).

Response:

Welland Hydro has verified the numbers used to allocate Account 1589 in the EDDVAR and can confirm that it incorrectly described the methodology for the Residential and GS<50 customer classes on Page 18 of Exhibit 9. Metered kWh for Non-RPP Customers for all customer classes was estimated using a percentage of 2015 actual Non-RPP to total kWh.

9-Staff-69
Ref: Exhibit 9, Page 25, DVA Continuity Schedule

Welland Hydro submits the IESO true up for RPP claims on a quarterly basis.

a) Please confirm that the IESO true up has not been included in the 2015-year end balances.

Response:

Welland Hydro can confirm the IESO true up for the period from October, 2015 to December, 2015 is not included in the 2015 year end balances. A change has been made in 2016 to include the fourth quarter IESO true up in year end balances.

b) Please indicate the IESO true up amounts for October to December 2015. Please also indicate what the Account 1588 and Account 1589 balances would be if the true up was included in the year-end balance.

Response:

	Account 1588	Account 1589
2015 Year End Balance	(4,001)	352,770
2015 Oct-Dec IESO True Up	(163,571)	109,356
TOTAL	(167,572)	462,126

<u>VECC – Exhibit 9</u>

9.0 –VECC -47
Reference: Exhibit 9/pg. 8 / Table 9-6 pg.14

a) Why/how does the premature failure of smart meter meet the criteria of IFRS-CGAAP transition amounts? Specifically, how were these meters previously pooled under CGAAP as compared to their subsequent accounting under IFRS.

Response:

Prior to the adoption of IFRS Welland Hydro pooled assets in account 1860 Meters. In other words, Welland Hydro tracked meter purchases by year and would depreciate until assets for that year were fully depreciated. No adjustments were made to gross asset value or accumulated depreciation for assets taken out of service. Since the adoption of IFRS retroactive to January 1, 2014 all asset accounts require adjustments to both gross asset value and accumulated depreciation when assets are removed from service. The 2013 COS application did not include amounts for the early retirement of assets. As a result, early retirement of assets are currently charged to account 1575 until a forecasted amount will be included in rates in the 2017 COS Rate Application.

9.0-VECC-48
Reference: E9/pg. 7

a) Please confirm that in its last cost of service application (EB-2012-0173) Welland received approval for the disposal of $46,162 in Incremental IFRS transition related costs as of December 31, 2012.

<u>Response</u>:

The $46,162 approved for disposal in the 2013 COS was for related costs as of December 31, 2011 including principal of $44,673 and interest of $1,489. The principal amounts were for 2011 of $24,673 and for 2012 of $20,000. The amounts for 2012 were not audited at the time of the settlement conference in the 2013 COS and were excluded from disposition.

b) Please show how in Table 9-5 the amount of $25,806 results from expenses incurred in 2013 through 2016.

<u>Response</u>:

Welland Hydro has requested a total of $26,404 including interest to cover IFRS cost from 2012 to 2016. A break-down is as follows:

Costs 2012	$4,265
Costs 2015	7,500
Costs 2016	14,250
Carry Charges to Dec 31/15	216
Carry Charges to Apr 30/17	172
TOTAL	$26,404

c) Please provide the amounts (separately) paid to KPMG and Deloitte in the period 2013 – 2016.

Response:

2012 Deloitte	$2,950
2012 EDA IFRS Conference (2)	1,315
2015 KPMG	7,500
2016 KPMG	4,250
2016 Deloitte	10,000
Total Principal 2012-2016	$26,015

APPENDIX A
CURRENT SHAREHOLDER DECLARATION (2016) &
DIVIDEND RESOLUTIONS (2013-2016)

CORPORATION OF THE CITY OF WELLAND

AMENDED AND RESTATED, 2016

SHAREHOLDER DECLARATION

WHEREAS Welland Hydro-Electric Holding Corp. (the "**Corporation**") is a corporation existing under the *Business Corporations Act* (Ontario);

AND WHEREAS the Corporation of the City of Welland (the "**Shareholder**") is the beneficial owner of all of the issued shares of the Corporation;

AND WHEREAS the Corporation and the Subsidiaries (together the "**Corporations**") are the successors to the Welland Hydro-Electric Commission;

AND WHEREAS the Corporation's business (the "**Business**") is integral to the well-being and infrastructure of the City of Welland;

AND WHEREAS the Business is subject to the provisions of the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* being Schedules A and B, respectively, to the *Energy Competition Act, 1998, S.O.*, c.15, as such statutes may be amended or re-enacted from time to time, to the regulations made pursuant to these statutes and to the various regulatory requirements of the Ontario Energy Board;

AND WHEREAS the Shareholder wishes to establish certain principles of governance relating to the Corporations and to set forth those matters which may be undertaken by the Corporations only with the approval of the Shareholder;

AND WHEREAS the Shareholder issued an Amended and Restated 2004 Shareholder Declaration containing all amendments to this Shareholder Declaration to December 21, 2004;

AND WHEREAS the Shareholder issued an Amended and Restated 2005 Shareholder Declaration containing all amendments to this Shareholder Declaration to December 6, 2005;

AND WHEREAS the Shareholder issued an Amended and Restated 2006 Shareholder Declaration containing all amendments to this Shareholder Declaration to May 9, 2006;

AND WHEREAS the Shareholder issued an Amended and Restated 2007 Shareholder Declaration containing all amendments to this Shareholder Declaration to May 1, 2007;

AND WHEREAS the Shareholder issued an Amended and Restated 2010 Shareholder Declaration containing all amendments to this Shareholder Declaration to June 8, 2010;

AND WHEREAS the Shareholder issued an Amended and Restated 2011 Shareholder Declaration containing all amendments to this Shareholder Declaration to June 14, 2011;

AND WHEREAS the Shareholder issued an Amended and Restated 2014 Shareholder Declaration containing all amendments to this Shareholder Declaration to April 1, 2014;

AND WHEREAS the Shareholder issued an Amended and Restated 2016 Shareholder Declaration containing all amendments to this Shareholder Declaration to June 28, 2016;

AND WHEREAS it is desirable to evidence further amendments in this Shareholder Declaration and to restate this Shareholder Declaration as hereinafter set forth;

NOW THEREFORE THIS DIRECTION AND DECLARATION WITNESSES:

ARTICLE 1 - INTERPRETATION

1.1 Definitions

Wherever used in this Shareholder Declaration, unless the context requires otherwise, the following terms shall have the respective meanings ascribed to them below.

"**Acquisition Threshold**" shall have the meaning set out in Subsection 9.12;

"**Act**" means the *Electricity Act, 1998* (Ontario);

"**Board**" means the board of directors of the Corporation;

"**Business Plan**" means a five year business plan and budget for the Corporation and the Subsidiaries prepared and approved in accordance with Section 10.1;

"**Chair**" means the chair of the Board;

"**Clerk**" means the Clerk of the City of Welland;

"**Corporation**" means Welland Hydro-Electric Holding Corp., incorporated pursuant to Section 142 of the Act;

"**Council**" means the city council of the Shareholder;

"**Day-To-Day Business Transactions**" means power bill payments, wholesale and retail customer rebates, customer deposits, rate setting and rate riders; receivable payments; revenues and expenditures; depreciation; taxes and payment in lieu of taxes; budget and capital program payments, dividend payments; loan payments; bank transactions and payroll and related expenditures.

"**Distribution Company**" means Welland Hydro-Electric System Corp. and any other Subsidiary that carries on the business described in Section 3.1(a) and that owns any distribution system, structures, equipment or property used for that purpose;

"**Financial Statements**" means, for any particular period, audited or unaudited (as stipulated in this Declaration), consolidated or unconsolidated (as stipulated in this Declaration), comparative financial statements of the Corporation consisting of not less than a balance sheet, a statement of income and retained earnings, a statement of changes in financial position, a report or opinion of the Auditor (in the case of audited Financial Statements) and such other statements, reports, notes and information prepared in accordance with generally accepted accounting principles (consistently applied) and as are required in accordance with any applicable law;

"**Independent Director**" means an individual who meets criteria as set out in section 2.1.2 of the Affiliate Relationship Code, unless they are: (a) a shareholder, director, officer or employee of an affiliate; (b) where the affiliate is a municipality, the mayor, or a member of the municipal council, a member of a "local board" as defined in the Municipal Act, 2001 or an employee of the municipality; and (c) an employee of the distributor.

"**IMO**" means the Independent Electricity Market Operator;

"**Mayor**" means the Mayor of the Corporation of the City of Welland;

"**Minor Acquisition**" shall have the meaning set out in Subsection 9.12;

"**Minor Transaction**" shall have the meaning set out in Subsection 9.12;

"**Nominating Committee**" means a committee of the Board established by the Board for the purpose set out in Subsection 5.9;

"**OBCA**" means the *Business Corporations Act* (Ontario);

"**OEB**" means the Ontario Energy Board;

"**President**" means the president and chief executive officer of the Corporation;

"**Private Directors**" shall have the meaning set out in Subsection 5.2;

"**Services Company**" means Welland Hydro-Energy Services Corp. and its subsidiaries, Welland WiFi Corp., and Welland Solar Corp., and any other Subsidiary that carries on the business described in Section 3.1(b) hereof;

"**Shareholder**" means the Corporation of the City of Welland;

"**Shareholder Declaration**" or "**Declaration**" means this shareholder declaration;

"**Shareholder Representative**" shall have the meaning set out in Subsection 6.1;

"**Subsidiaries**" means the subsidiary corporations (as defined in the OBCA) of the Corporation;

"**Subsidiary**" means, with respect to the Corporation, any body corporate of which more than 50% of the outstanding securities of any class carrying exercisable voting rights are beneficially owned, directly or indirectly, by the Corporation, and includes any body corporate in like relation to a Subsidiary. The Subsidiaries are Welland Hydro-Electric System Corp., Welland Hydro Energy Services Corp., Welland WiFi Corp. and Welland Solar Corp.

"**Transaction**" means a binding commitment, contract or agreement, excluding Day-To-Day Business Transactions.

"**Transaction Threshold**" shall have the meaning set out in Subsection 9.12; and

"**Vice-Chair**" means the vice-chair of the Board.

1.2 Calculation of Time

In this Declaration, a period of days will be deemed to begin on the first day after the event which began the period and to end at 5:00 p.m. (Welland time) on the last day of the period. If, however, the last day of the period does not fall on a business day, the period will terminate at 5:00 p.m. (Welland time) on the next business day.

1.3 Paramountcy

In the event of any inconsistency between the terms of this Declaration and the terms of the articles or the by-laws of the Corporation or any of its Subsidiaries, the terms of this Declaration shall prevail to the extent of the conflict.

ARTICLE 2 - EXPECTATIONS AND PRINCIPLES

2.1 Purposes

The purposes of this Declaration are as follows:

(a) subject to the Board's authority to manage or supervise the management of the business and affairs of the Corporations, to provide the Board with the Shareholder's expectations relating to the principles of governance and other fundamental principles and policies regarding the Business;

(b) to inform the residents of the City of Welland of the Shareholder's fundamental principles regarding the Business; and

(c) to set out the accountability, responsibility and relationship between the Board and the Shareholder.

Except as provided in Article 6 and Article 9 hereof, this Declaration is not intended to constitute a unanimous shareholder declaration under the OBCA or to formally restrict the exercise of the powers of the Board.

2.2 Shareholder Expectations

The Shareholder expects that the Board will establish policies and practices to:

(a) develop and maintain a prudent financial and capitalization structure for the Corporation and its Subsidiaries consistent with OEB benchmarks and sound financial principles and established on the basis that the Corporation and its Subsidiaries are intended to be self-financing entities;

(b) establish just and reasonable rates for the regulated Distribution Company of the Corporation, or any of its Subsidiaries, which are:

(i) as permitted by the Ontario Energy Board;

(ii) intended to preserve the value of the Corporation and its Subsidiaries; and

(iii) consistent with the encouragement of economic development and activity within the City of Welland;

(c) provide service with reliability and service quality consistent with Ontario electric utility standards of utilities of comparable size;

(d) provide the Shareholder with a return on equity for the regulated Distribution Company that is zero or as close to zero as is practically possible consistent with ensuring that there is adequate capital to pay for new investment without borrowing (or with minimum debt) as capital is required, and is consistent with maintaining just and reasonable rates;

(e) manage all risks related to the business conducted by the Corporation and its Subsidiaries, through the adoption of appropriate risk management strategies and internal controls consistent with industry norms; and

(f) develop a long range strategic plan for the Corporation and its Subsidiaries which is consistent with the maintenance of a viable, competitive business and preserves the value of the Business.

2.3 Principles

The following principles will govern the operations of the Corporations:

(a) The Business is integral to the well being and the infrastructure of the City of Welland. The Corporation recognizes that it is in the best interests of the Corporations and the community of stakeholders whom the Business affects that the Corporations conduct their affairs:

(i) on a commercially prudent and efficient basis;

(ii) in a manner consistent with the energy policies as may be established by the Shareholder from time to time;

(b) The Distribution Company will provide, a reliable, effective and efficient electricity distribution system.

(c) Distribution rates applicable to customers of the Distribution Company will be approved by the Board to be fair to all classes of customers and to achieve zero or near-zero return in accordance with Section 2.2 above.

(d) The Business is at all times subject to such licences, codes, policies, rules, orders, interim orders, approvals, consents and other actions of any Regulator.

(e) The Distribution Company will provide its services with an emphasis on customer satisfaction, achieving, at a minimum, the customer service indicators and service reliability indicators accepted from time to time by the Ontario Energy Board.

(f) The Corporations will operate in a safe and environmentally responsible manner.

(g) The Distribution Company will promote energy conservation and environmental responsibility.

(h) The Board is responsible for determining and implementing the appropriate balance among the foregoing principles and for causing the Corporations to conduct their affairs in accordance with the same.

ARTICLE 3 - BUSINESS OF THE CORPORATIONS

3.1 Business of the Corporations

Subject to the ongoing ability of the Corporations to meet the financial objectives of the Shareholder set out in this Declaration and the ability of the Board to demonstrate the same, the Corporations may engage in any of the following business activities:

(a) the Distribution Company may engage only in the following business activities:

(i) providing standard supply service and promote energy conservation, as required by the OEB or other legislative authority,

(ii) distributing electricity and associated services to customers of the Distribution Company, its affiliates, and provided Welland residents receive preferential treatment, such others as may be licensed or authorized by the OEB to provide electrical or other utility services,

(iii) subject to Shareholder approval, new business activities, the principal purpose of which is to use more effectively the assets of the Distribution Company:

(iv) subject to Shareholder approval and applicable legislation, new business activities the principal purpose of which is to use more effectively the assets of the Corporation or any Subsidiary, as applicable, including providing meter installation and reading services, providing billing services, and business activities in the telecommunications area, and

(v) generating renewable energy and participating in renewable energy projects, energy storage, district heating and other similar business activities as permitted by applicable legislation.

(b) the Services Company may engage only in the following business activities entry into each of which is subject to the approval of the Board of the Corporation:

(i) subject to Shareholder approval, retailing electricity;

(ii) renting or selling fibre-optic and/or wireless services, water heaters, plenum heaters, sentinel lights and traffic lights:

(iii) providing services relating to improving energy efficiency:

(iv) investigate and research business activities that develop or engage the ability of the Services Company to carry on any of the activities contemplated by the other subsections of this Section 3.1(b)

(v) subject to Shareholder approval, business activities that develop or engage the ability of the Services Company to carry on any of the activities contemplated by the other subsections of this Section 3.1(b); and

(vi) generating renewable energy and participating in renewable energy projects, energy storage, district heating and other similar business activities as permitted by applicable legislation.

ARTICLE 4 – STANDARDS OF GOVERNANCE

4.1 As required by the OBCA, the Board and the board of directors of any Subsidiary shall supervise the management of the business and affairs of the Corporation and any Subsidiary respectively, and, in so doing, shall act honestly and in good faith with a view to the best interests of the Corporation or the Subsidiary respectively and shall exercise the same degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

ARTICLE 5 - BOARD OF DIRECTORS

5.1 Number of Directors

(a) The Corporation shall be governed by the Board which shall consist of a minimum of three (3) and a maximum of nine (9) directors to be appointed by the Shareholder. The Shareholder shall, by special resolution, designate the number of members of the Board to hold office from time to time. On the date of this Declaration, the Board shall be comprised of four (4) directors.

(b) The Distribution Company shall be governed by a board of directors which shall consist of a minimum of five (5) and a maximum of nine (9) directors to be appointed by the Shareholder. The Shareholder shall, by special resolution, designate the number of members of the board of directors to hold office from time to time. On the date of this Declaration, the board of directors shall be comprised of six (6) directors.

(c) The Services Company and its Subsidiaries, Welland WiFi Corp., and Welland Solar Corp., shall be governed by a board of directors which shall consist of a minimum of three (3) and a maximum of nine (9) directors to be appointed by the Shareholder. The Shareholder shall, by special resolution, designate the number of members of the board of directors to hold office from time to time. On the date of this Declaration, the board of directors shall be comprised of four (4) directors.

5.2 Board Composition

(a) The Board of the Corporation shall be comprised of four (4) members, which shall include:

(i) the Mayor;

(ii) the President and Chief Executive Officer of the Corporation;

(iii) two (2) directors, who shall not be members of Council (the "Private Directors");

(b) The board of directors of the Distribution Company shall be comprised of:

(i) the three directors of the Corporation except the Mayor;

(ii) one other member of Council, except the Mayor, (the "Councillor"); and

(iii) two independent directors who shall not be members of Council (the "Private Directors").

(c) The board of directors of the Services Company and Welland WiFi Corp. and Welland Solar Corp. shall be comprised of the four (4) directors of the Corporation.

5.3 Board of the Distribution Company

(a) The board of the Distribution Company must at all times be comprised of at least three (3) directors with significant direct business experience and one (1) director with direct knowledge of community issues, as defined and evaluated by the board of the Distribution Company.

(b) At least one third of the board of directors of the Distribution Company are to be independent directors from any affiliate of the Distribution Company (currently the Corporation and the Services Company).

5.4 Qualification of Directors

In addition to sound judgment and personal integrity, the qualifications of candidates for the Board or the board of directors of any Subsidiary may include:

(a) awareness of public policy issues related to the Corporation or a Subsidiary, as applicable;

(b) business expertise (including retail experience);

(c) experience on boards of corporations or other organizations;

(d) financial, legal, accounting and/or marketing experience;

(e) regulated industry knowledge including, but not limited to, knowledge of municipal electric utilities;

(f) knowledge and experience with risk management strategy; and

(g) experience as a member of senior management in the service industry or educational institutions.

5.5 Residency

Preference will be given to qualified candidates for the Board who are residents of the City of Welland, however non-residents shall not be excluded from serving as Board members.

5.6 Chair and Vice-Chair Positions

The Board may elect its own Chair and Vice-Chair. However, neither the Mayor nor the President and Chief Executive Officer may serve as the Chair or Vice-Chair.

5.7 Term

(a) The term for each member of the Board shall be as follows:

   (i) The Mayor serving as a member of the Board shall serve for a term coincident with his or her term on Council.

   (ii) The President and Chief Executive Officer shall serve as a member of the Board for a term coincident with his or her term as President and Chief Executive Officer.

   (iii) Subject to a transition period, the two (2) Private Directors shall be appointed to serve as members of the Board for a Three year term.

(b) The three (3) common directors on the board of directors of each of the Corporation, the Distribution Company and the Services Company will serve for the same term.

(c) The term of no more than two (2) Private directors will end in any one year on the board of the Distribution Company and the term of no more than one director will end in any one year on the board of each of the Corporation and the Services Company.

(d) The term of the two (2) independent directors on the board of the Distribution Company will not end in the same year.

(e) The term of no more than one (1) director will end in any one year on the Board of the Corporation and the board of the Services Company.

(f) If a member of the Board ceases to be a director for any reason, the Shareholder will fill the vacancy created thereby as soon as reasonably possible. If a member of the board of directors of any Subsidiary ceases to be a director for any reason, the Corporation will cause the vacancy to be filled by another director of the Corporation as soon as reasonably possible, subject to, and in compliance with the OEB Affiliate Relationships Code. All directors of the Corporation appointed to fill vacancies of the Board shall serve for the balance of the term of the director(s) replaced.

(g) Any member of the Board may serve for successive terms as determined by the Shareholder.

5.8 Board Committees

(a) The Board may establish committees of the Board in the Board's discretion. The Shareholder anticipates that the Board will establish the following committees:

(i) Audit and Finance Committee to review financial results;

(ii) Governance Committee;

(iii) Nominating Committee to evaluate and recommend to the Shareholder potential candidates, for the boards of the Corporation and the Subsidiaries.

(b) The board of directors of each of the Subsidiaries may establish committees in the discretion of each such board. The Shareholder anticipates that the board of the Distribution Company will establish the following committees:

(i) Audit and Finance Committee to review financial results;

(ii) Governance Committee;

(iii) Operations, Health, Safety and Environment Committee;

(iv) Compensation Committee.

The Shareholder also anticipates that the board of the Services Company will establish the following committees:

(i) Audit and Finance Committee to review financial results;

(ii) Governance Committee.

5.9 Role and Composition of Nominating Committee

(a) The Shareholder shall consider candidates for the Board and the boards of directors of the Subsidiaries nominated by the Nominating Committee of the Board, but shall not be obliged to select such candidates. It is expected that the Nominating Committee will develop a process to identify and evaluate potential Board candidates and candidates for the boards of directors of the Subsidiaries in order to recommend a slate of qualified candidates to the Shareholder.

(b) The Nominating Committee will be composed of:

(i) the Mayor;

(ii) the President and Chief Executive Officer of the Corporation;

(iii) one director from the Corporation selected by its Board;

(iv) and one independent director from the Distribution Company selected by its Board.

No Private Director shall be eligible to be a member of the Nominating Committee if his or her term as a board member is ending at the next Annual Shareholder Meeting or at a Special Meeting of the Shareholder for appointing directors.

5.10 Directors' Compensation

The compensation of the Board and the board of directors of the Subsidiaries shall be approved by the Shareholder. The Chair of the Board and the Chair of the board of each of the Subsidiaries shall be compensated in the amount of six thousand dollars ($6,000) per annum and three hundred dollars ($300) for each Board and committee meeting attended, effective January 1, 2014. The Private Directors shall be compensated in the amount of five thousand dollars ($5,000) per annum and two hundred dollars ($200) for each Board and committee meeting attended, effective January 1, 2012. As of January 1, 2015, the Private Directors shall be compensated in the amount of two hundred and fifty dollars ($250) for each Board and committee meeting attended. The Mayor and the Councillor shall be compensated in the amount of two thousand five hundred dollars ($2,500) per annum and two hundred dollars ($200) for each Board and committee meeting attended, effective January 1, 2012. As of January 1, 2015, the Mayor and the Councillor shall be compensated in the amount of two hundred and fifty dollars ($250) for each Board and committee meeting attended. Members of the Board who are also members of the board of directors of a Subsidiary shall not receive additional compensation for acting as a director of the Subsidiary. The President and Chief Executive Officer of the Corporation shall not be paid any annual fee or attendance fee for his or her role as a member of the Board. The annual compensation for board members will be increased annually by the same annual percentage increase as received by the members of Welland City Council. All board members (except the President and Chief Executive Officer of the Corporation) will receive a per diem of two hundred and fifty dollars ($250) per day, effective January 1, 2014, to ensure board members attend approved education sessions as prescribed by the Board and the board of directors of the Subsidiaries, from time to time.

5.11 Conflict of Interest Policy

The directors and officers of the Corporation and the Subsidiaries will strictly abide by the requirements of the OBCA and the conflict of interest rules set forth in the Bylaws of the Corporation and the Subsidiaries including any requirements in respect of disclosure and abstention from voting.

5.12 Confidentiality

The Shareholder and the directors and officers of the Corporation and the Subsidiaries (each a "**Receiving Party**") will ensure that no confidential information of the Shareholder or the Corporations is disclosed or otherwise made available to any person, except to the extent that:

(a) disclosure to a Receiving Party's employees or agents is necessary for the performance of any Receiving Party's duties and obligations under this Declaration:

(b) disclosure is required in the course of judicial proceedings or pursuant to law; or

(c) the confidential information becomes part of the public domain (other than through unauthorized disclosure by the Receiving Party).

A detailed confidentiality policy consistent with the practices of corporate governance will be established by the Corporation and will form a part of the Bylaws of the Corporation;

5.13 Open Board Meetings

The Shareholder hereby directs that the meetings of the Board of Directors of the Corporation (and Welland Hydro-Electric System Corp.) are to be open to the public subject to the exceptions and procedures prescribed by the By-Laws of the Corporation (and Welland Hydro-Electric System Corp.)

ARTICLE 6 - DECISIONS OF THE SHAREHOLDER AND SHAREHOLDER REPRESENTATIVE

6.1 The Shareholder hereby designates the Mayor or the Mayor's representative and the Clerk, the Chief Administrative Officer or the City Manager as the legal representative of the Shareholder (the "**Shareholder Representative**") for purposes of conveying to the Board, pursuant to Subsection 6.2, any legal consent or approval required by this Shareholder Declaration or by the OBCA or otherwise.

6.2 Approvals or decisions of the Shareholder required pursuant to this Shareholder Declaration or the OBCA shall require a resolution or by-law of Council passed at a meeting of Council and shall be communicated in writing to the Board and signed by the Shareholder Representative.

ARTICLE 7 - MEETINGS AND ANNUAL RESOLUTIONS

Within eight (8) months after the end of each fiscal year of the Corporation:

7.1 Annual Report to Meeting of Council

The Board shall report to a meeting of Council and the Chair and the President shall attend such meeting and provide such information concerning the Corporation and its Subsidiaries as is appropriate, as determined by the Corporation.

7.2 Annual Resolutions:

(a) The Shareholder shall consider candidates for the Board as proposed by the Nominating Committee and the appointment of the auditors of the Corporation and receive the audited financial statements of the Corporation for the last completed fiscal year.

(b) The Shareholder, by resolution in writing signed by the Shareholder Representative in accordance with Section 6, shall appoint the necessary members of the Board and appoint the auditors for the Corporation and complete such other business as would normally be completed at an annual meeting of the shareholder under the OBCA.

(c) The Corporation, as the sole shareholder of the Subsidiaries, shall consider candidates for the board of directors of each of the Subsidiaries as proposed by the Nominating Committee and the appointment of the auditors of the Subsidiaries and receive the audited financial statements of the Subsidiaries for the last completed fiscal year.

(d) The Corporation, as the sole shareholder of the Subsidiaries, by resolution in writing signed by the Shareholder Representative in accordance with Section 6 shall appoint the necessary members of the boards of each of the Subsidiaries and appoint the auditors for the Subsidiaries and complete such other business as would normally be completed at an Annual Meeting of the Shareholder under the OBCA.

ARTICLE 8 - REPORTING ON MAJOR DEVELOPMENTS

8.1 The Board may from time to time report to Council on major business developments or materially significant or adverse results as the Board, in its discretion, considers appropriate and such reports may be received and considered by the Shareholder at a meeting of Council.

8.2 The board of a Subsidiary may request a meeting with Council to discuss any direction received from the Corporation that the board of the Subsidiary believes is not in the best interests of the Subsidiary. Prior to requesting a meeting with Council, the board of the Subsidiary will attempt to deal with the issue with the Corporation. If the board of the Subsidiary and the Corporation are not able to resolve the issue, the board of the Subsidiary will give prior written notice to the Corporation of its intention to request a meeting with Council to discuss the issue.

8.3 Council may, from time to time, request that a senior member of the Corporation's management and/or a member of the Board attend at a public meeting of Council and respond to questions raised by Council or the general public concerning the Corporation and/or its Subsidiaries.

ARTICLE 9 - MATTERS REQUIRING SHAREHOLDER APPROVAL

Without Shareholder approval given in accordance with Section 6, the Corporation or any Subsidiary, respectively, shall not:

Statutory Approval Rights

9.1 Change the name of the Corporation or a Subsidiary; add, change or remove any restriction on the business of the Corporation or a Subsidiary; create new classes of shares; or in any other manner amend its articles of incorporation or make, amend or repeal any by-law;

9.2 Amalgamate with any other corporation(s) other than amalgamations which may, under the OBCA, be approved by a resolution of directors;

9.3 Take or institute proceedings for any winding-up, arrangement, or dissolution of the Corporation or a Subsidiary;

9.4 Apply to continue as a corporation under the laws of another jurisdiction;

9.5 Sell or otherwise dispose of, by conveyance, transfer, lease, sale and leaseback, or other transaction, all or substantially all of its assets or undertaking;

9.6 Change the Auditor;

9.7 Make any change to the number of directors comprising the Board;

9.8 Enter into any transaction or take any action that requires shareholder approval pursuant to the OBCA.

<u>**Additional Approval Rights**</u>

9.9 Issue, or enter into any agreement to issue, any shares of any class, or any securities convertible into any shares of any class, of the Corporation or a Subsidiary;

9.10 Redeem or purchase any of its outstanding shares;

9.11 Acquire any electricity distribution business outside of the municipal boundaries of the Shareholder; and

9.12 Enter into any joint venture, partnership, strategic alliance or other venture or Transaction, including, without limitation, ventures in respect of the generation or co-generation of electricity, which would require an investment, or which would have a financial impact in any fiscal year greater than (i) 10% of the net book value of the assets of Welland Hydro-Electric System Corp; (ii) \$200,000 for each of the Corporation; Welland Hydro Energy Services Corp., Welland WiFi Corp, and Welland Solar Corp. (each a "Transaction Threshold"). The amount of all Transactions which the Corporation or a Subsidiary concludes under this Subsection 9.12 and which is below the applicable Transaction Threshold ("Minor Transaction") shall be added together, and when any subsequent proposed Transaction would exceed the applicable Transaction Threshold when added to the aggregate of the Minor Transactions in any fiscal year, Shareholder approval shall be required as described herein, notwithstanding that the proposed Transaction may not, by itself, exceed the applicable Transaction Threshold;

9.13 Make any decision that would materially adversely affect the tax or regulatory status of the Corporation or any of its Subsidiaries;

9.14 Enter into any business activity not permitted under Section 3.1 hereof;

9.15 Provide any financial assistance, whether by loan, guarantee or otherwise, to any director or officer of the Corporation or of any Subsidiary or Associate;

9.16 Establish a new Subsidiary;

9.17 Change the remuneration for the members of the Board as provided for in Section 5.10 hereof.

ARTICLE 10 - REPORTING

10.1 Business Plan

Not later than sixty (60) days prior to the end of each fiscal year, the Board will approve and submit to the Finance Department of the Shareholder (the "**Finance Department**") a business plan for the Corporations for the next five fiscal years (the "**Business Plan**"). The Business Plan will be prepared on a consistent basis with the Business Plan then in effect. The Corporation will carry on its business and operations in accordance with the Business Plan which will include, in respect of the period covered by such plan:

(a) the strategic direction and any new business initiatives which the Corporations will undertake;

(b) an operating and capital expenditure budget for the next fiscal year and an operating and capital expenditure projection for each fiscal year thereafter, including the resources necessary to implement the draft business plan;

(c) pro forma consolidated and unconsolidated financial statements showing at a minimum the projected annual revenues and expenditures for each business activity for each fiscal year for the Corporation and each of the Subsidiaries;

(d) any material variances in the projected ability of any business activity to meet or continue to meet the financial objectives of the Shareholder; and

(e) any material variances from the Business Plan then in effect.

10.2 Quarterly Reports

Within 45 days after the end of each fiscal quarter, the Board will prepare (on a consistent basis with, the previous fiscal quarter) and submit to the Finance Department a quarterly report. The quarterly report will include, in respect of the immediately preceding fiscal quarter:

(a) quarterly unaudited consolidated and unconsolidated Financial Statements;

(b) such explanations, notes and information as is required to explain and account for any variances between the actual results from operations and the budgeted amounts set forth in the current Business Plan, including any material variances in the projected ability of any business activity to meet or continue to meet the financial objectives of the Shareholder;

(c) information that is likely to materially affect the Shareholder's financial objectives or energy policies;

(d) information that is likely to materially affect customers' perceptions or opinions regarding the Corporations:

(e) information regarding any matter, occurrence or other event which is a material breach or violation of any law; and

(f) any such additional information as the Shareholder may specify from time to time.

10.3 Access to Records

The Shareholder may, by resolution, appoint a representative who shall have unrestricted access to the books and records of the Corporation and the Subsidiaries during normal business hours. In addition to any such appointees, the Treasurer, the Chief Administrative Officer and/or the City Manager of the City of Welland are, by virtue of their offices, representatives. All such representatives shall treat all information of the Corporations with the same level of care and confidentiality as any confidential information of the Shareholder.

10.4 Audit

The Corporation's consolidated and unconsolidated Financial Statements will be audited annually. The auditor of the Corporation is Deloitte & Touche LLP, Chartered Accountants (the "**Auditor**").

10.5 Accounting

The Corporation will, in consultation with the Auditor, adopt and use the accounting policies and procedures which may be approved by the Board from time to time and all such policies and procedures will be in accordance with generally accepted accounting principles and applicable regulatory requirements.

10.6 Annual Financial Statements

The Board will cause the Auditor to deliver, as soon as practicable and in any event within one hundred and twenty (120) days after the end of each fiscal year, the audited consolidated Financial Statements of the Corporation for consideration by the Shareholder.

ARTICLE 11 - FINANCIAL PERFORMANCE

11.1 Financial Performance

The Board will implement and maintain policies to:

(a) *Capital Structure* - develop and maintain a prudent financial and capitalization structure for the Corporation and its Subsidiaries consistent with OEB benchmarks and sound financial principles, established on the basis that the

Corporation and its Subsidiaries are each intended to be self-financing entities on an ongoing basis;

(b) *Distribution Rates* - ensure the establishment of just and reasonable rates for the regulated distribution business of the Corporation, or any of its Subsidiaries, which are:

(i) as permitted by the OEB;

(ii) intended to preserve the value of the Corporation and its Subsidiaries; and

(iii) consistent with the encouragement of economic development and activity within the Shareholder;

(c) *Returns* - preserve Shareholder value by providing a high level of service reliability and quality, meeting revenue and expenditure targets consistent with prudent and efficient financial goals, and generating a return on equity as provided for in Section 2.2(d) hereof.

(d) *Risk Management* - manage all risks related to the business conducted by the Corporation and its Subsidiaries, through the adoption of appropriate risk management strategies and internal controls consistent with industry norms.

11.2 Operation Policy

The Corporations will:

(a) employ the most efficient cost structure available for like businesses;

(b) mandate the creation and implementation of cost reduction programs to ensure that capital and labour costs are minimized; and

(c) operate at a level of reliability and service quality which at least meets OEB requirements and is equal to or better than the average reliability and service levels of other Ontario utilities of comparable size.

ARTICLE 12- REVISIONS TO THIS DECLARATION

The Shareholder acknowledges that this Shareholder Declaration may be revised from time to time as circumstances may require and that the Shareholder will consult with the Board prior to completing any revisions and will promptly provide the Board with copies of such revisions.

DATED at Welland, Ontario as of this 28 day of JUNE, 2016.

THE CORPORATION OF THE CITY OF WELLAND

Per: ________________________

Name: Frank Campion

Title: Mayor

Per: ________________________

Name: Tara Stephens

Title: Acting City Clerk

We have the authority to bind the corporation

Corporation of Welland

CITY OF WELLAND
City Clerk and Legal Services
Office of the City Clerk
Corporate Services
60 East Main Street, Welland, ON L3B 3X4
Phone: 905-735-1700 ext. 2280 Fax: 905-732-1919
E-mail: clerk@welland.ca
www.welland.ca

May 28, 2013

File No. 99-43

Mr. Ross Peever, President
Welland Hydro Electric Holding Corporation
950 East Main Street
P.O. Box 280
Welland, ON L3B 5P6

RE: May 21, 2013 – WELLAND CITY COUNCIL

Dear Mr. Peever,

At its meeting of May 21, 2013, Welland City Council passed the following Motion:

> **"THAT THE COUNCIL OF THE CITY OF WELLAND, as sole Shareholder of Welland Hydro-Electric Holding Corp., requests and accepts excess funds of $500,000.00 by way of a dividend from Welland Hydro-Electric Holding Corp., notwithstanding the terms of the Shareholder Declaration."**

Yours truly,

Christine Raby
City Clerk

CR:sm

c K. Douglas, General Manager, Corporate Services/City Treasurer
C. Stirtzinger, City Manager

RECEIVED
JUN 12 2013

CITY OF WELLAND
Legislative Services
Office of the City Clerk
60 East Main Street, Welland, ON L3B 3X4
Phone: 905-735-1700 ext. 2280 Fax: 905-732-1919
E-mail: clerk@welland.ca
www.welland.ca

May 12, 2014 **File No. 99-43**

Welland Hydro-Electric Holding Corporation
950 East Main Street
P.O. Box 280
Welland, ON L3B 5P6

Attention: Mr. Ross Peever, President & CEO

Dear Mr. Peever:

RE: May 6, 2014 – WELLAND CITY COUNCIL

At its meeting of May 6, 2014, Welland City Council passed the following motion:

> **"THAT THE COUNCIL OF THE CITY OF WELLAND, as sole Shareholder of Welland Hydro-Electric Holding Corp., requests and accepts excess funds of $500,000 by way of a dividend from Welland Hydro-Electric Holding Corp., notwithstanding the terms of the Shareholder Declaration."**

Yours truly,

for Christine Raby
City Clerk

CR:sm

Encl.

c - K. Douglas, General Manager, Corporate Services/City Treasurer
- C. Stirtzinger, City Manager

REF. NO. 99-43

Corporation of Welland

MOTION

COUNCILLORS	YEAS	NAYS
LAROUCHE		
PETRACHENKO		
CARL		
GRENIER		
MCLEOD		
DIMARCO		
LETOURNEAU		
CHIOCCHIO		
CAMPION		
GRIMALDI		
WRIGHT		
BELCASTRO		
MAYOR SHARPE		

MOVED BY: Larouche

SECONDED BY: Letourneau

THAT THE COUNCIL OF THE CITY OF WELLAND, as sole Shareholder of Welland Hydro-Electric Holding Corp., requests and accepts excess funds of $500,000 by way of a dividend from Welland Hydro-Electric Holding Corp., notwithstanding the terms of the Shareholder Declaration.

PRESENTED TO COUNCIL
MAY 06 2014
CITY OF WELLAND

CARRIED ✓

LOST

NOT PUT

AGENDA PAGE NUMBER 103 - 104

Corporation of Welland

REF. NO. 99-43

MOTION

COUNCILLORS	YEAS	NAYS
LAROUCHE		
PETRACHENKO		
CARL		
CHIOCCHIO J.		
MCLEOD		
DIMARCO		
LETOURNEAU		
CHIOCCHIO P.		
GRIMALDI		
FOKKENS		
MASTROIANNI		
VAN VLIET		
MAYOR CAMPION		

MOVED BY: Larouche

SECONDED BY: Mastroianni

THAT THE COUNCIL OF THE CITY OF WELLAND, as sole shareholder of Welland Hydro-Electric Holding Corp., requests an additional hydro dividend of $115,000, in addition to the base Hydro Dividend of $500,000, by way of a special dividend from Welland Hydro-Electric Holding Corp., notwithstanding the terms of the Shareholder Declaration.

PRESENTED TO COUNCIL
MAY 19 2015
CITY OF WELLAND

CARRIED ✓
LOST
NOT PUT

PRESENTED TO COUNCIL

MAY 19 2015

CITY OF WELLAND

COUNCIL

CORPORATE SERVICES

FINANCE DIVISION

APPROVALS	
GENERAL MANAGER	
TREASURER	
CITY MANAGER	

99-43

REPORT FIN-2015-15
MAY 19, 2015

SUBJECT: ADDITIONAL HYDRO DIVIDEND - 2015

AUTHOR &
APPROVING G.M.: STEVE ZORBAS, CPA, CMA, B. Comm, DPA,
GENERAL MANAGER, CORPORATE SERVICES/ TREASURER

RECOMMENDATION:

THAT THE COUNCIL OF THE CITY OF WELLAND, as sole shareholder of Welland Hydro-Electric Holding Corp., requests an additional hydro dividend of $115,000, in addition to the base Hydro Dividend of $500,000, by way of a special dividend from Welland Hydro-Electric Holding Corp., notwithstanding the terms of the Shareholder Declaration.

ORIGIN AND BACKGROUND:

Welland Hydro-Electric Systems (WHES) has a policy to provide dividends to Welland Hydro Holding Corporation (WHHC) which in turn are distributed to its sole shareholder, the Corporation of the City of Welland. The City annually receives a base amount dividend representing 60% of the planned net income which approximates $500,000.

Additional dividends can be requested and have been provided in the past when available. In October of 2013, WHES developed a policy to address dividend allocation for both the base amount and additional dividend which was presented at the WHHC Annual Shareholders meeting on June 24, 2014. The policy provides that additional dividends above the base amount can be provided for capital or one-off projects that are sustainable, or clean energy related and will help to reduce operating costs or provide a reasonable revenue stream. The City is requesting a special 2015 dividend request of $115,000 for additional funding (East Main Street Bridge LED Lighting project).

COMMENTS AND ANALYSIS:

A project to provide accent spot lighting on the East Main Street Bridge coincided with the recent restoration by the Region of Niagara of this designated historically significant heritage bridge. By enabling accent lighting of the bridge with energy efficient lighting, the heritage components of the bridge can be highlighted and showcased for people coming downtown for events and dining, late evening strolls or drives in the City. In 2014, the City received a special dividend in the amount of $138,000.

The Region of Niagara has budgeted $253,000 to install LED streetlighting on the East Main Street Bridge. The accent lighting project is estimated at $506,000. The City has approved funding of 50% ($253,000) of the project cost and the Region has approved the remaining 50% funding ($253,000).

FINANCIAL CONSIDERATION:

In 2014, the City received a special dividend of $138,000 towards this project. The City's share of this project is to be funded by the additional hydro dividend request of $115,000.

OTHER DEPARTMENT IMPLICATIONS:

Finance will request the dividend from Hydro and Engineering will co-ordinate the projects.

SUMMARY AND CONCLUSION:

Whereas additional dividends can be requested and have been provided in the past when available, it is therefore prudent for the City of Welland to request such additional dividends for the purpose of capital or one-off projects that are sustainable, or clean energy related and will help reduce the operating costs or provide reasonable revenue stream.

ATTACHMENTS:

N/A.

CITY OF WELLAND
Legislative Services
Office of the City Clerk
60 East Main Street, Welland, ON L3B 3X4
Phone: 905-735-1700 ext. 2159 Fax: 905-732-1919
E-mail: clerk@welland.ca
www.welland.ca

February 18, 2016 **File No. 99-43**

Welland Hydro-Electric Holding Corporation
950 East Main Street
P.O. Box 280
Welland, ON L3B 5P6

Attention: Mr. Ross Peever, President & CEO

Dear Mr. Peever:

RE: February 16, 2016 – WELLAND CITY COUNCIL

At its meeting of February 16, 2016, Welland City Council passed the following motion:

> **"THAT THE COUNCIL OF THE CITY OF WELLAND, as sole Shareholder of Welland Hydro-Electric Holding Corp., requests and accepts excess funds of $500,000 by way of a dividend from Welland Hydro-Electric Holding Corp., notwithstanding the terms of the Shareholder Declaration."**

Yours truly,

Stephens

Tara Stephens
Acting City Clerk

TS:cp

cc: - S. Zorbas, General Manager, Corporate Services/Treasurer

APPENDIX B
REVISED BILL IMPACTS

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0532
Proposed/Approved Loss Factor	1.0476

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 18.76	1	$ 18.76	$ 22.91	1	$ 22.91	$ 4.15	22.12%
Distribution Volumetric Rate	$ 0.0105	750	$ 7.88	$ 0.0077	750	$ 5.78	$ (2.10)	-26.67%
Fixed Rate Riders	$ 0.50	1	$ 0.50	$ 0.24	1	$ 0.24	$ (0.26)	-52.00%
Volumetric Rate Riders	$ -	750	$ -	-$ 0.0001	750	$ (0.08)	$ (0.08)	
Sub-Total A (excluding pass through)			$ 27.14			$ 28.85	**$ 1.72**	**6.32%**
Line Losses on Cost of Power	$ 0.1114	40	$ 4.44	$ 0.1114	36	$ 3.98	$ (0.47)	-10.53%
Total Deferral/Variance Account Rate Riders	-$ 0.0019	750	$ (1.43)	-$ 0.0015	750	$ (1.13)	$ 0.30	-21.05%
GA Rate Riders				$ -	750	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 30.94**			**$ 32.49**	**$ 1.55**	**5.00%**
RTSR - Network	$ 0.0078	790	$ 6.16	$ 0.0077	786	$ 6.05	$ (0.11)	-1.81%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0061	790	$ 4.82	$ 0.0060	786	$ 4.71	$ (0.10)	-2.16%
Sub-Total C - Delivery (including Sub-Total B)			**$ 41.92**			**$ 43.26**	**$ 1.33**	**3.18%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	790	$ 2.84	$ 0.0036	786	$ 2.83	$ (0.02)	-0.53%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	790	$ 1.66	$ 0.0021	786	$ 1.65	$ (0.01)	-0.53%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
Ontario Electricity Support Program (OESP)	$ 0.0011	790	$ 0.87	$ 0.0011	786	$ 0.86	$ (0.00)	-0.54%
TOU - Off Peak	$ 0.0870	488	$ 42.41	$ 0.0870	488	$ 42.41	$ -	0.00%
TOU - Mid Peak	$ 0.1320	128	$ 16.83	$ 0.1320	128	$ 16.83	$ -	0.00%
TOU - On Peak	$ 0.1800	135	$ 24.30	$ 0.1800	135	$ 24.30	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 131.09**			**$ 132.39**	**$ 1.30**	**0.99%**
HST	13%		$ 17.04	13%		$ 17.21	$ 0.17	0.99%
Total Bill on TOU			**$ 148.13**			**$ 149.60**	**$ 1.47**	**0.99%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	308 kWh
Demand	- kW
Current Loss Factor	1.0532
Proposed/Approved Loss Factor	1.0476

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 18.76	1	$ 18.76	$ 22.91	1	$ 22.91	$ 4.15	22.12%
Distribution Volumetric Rate	$ 0.0105	308	$ 3.23	$ 0.0077	308	$ 2.37	$ (0.86)	-26.67%
Fixed Rate Riders	$ 0.50	1	$ 0.50	$ 0.24	1	$ 0.24	$ (0.26)	-52.00%
Volumetric Rate Riders	$ -	308	$ -	-$ 0.0001	308	$ (0.03)	$ (0.03)	
Sub-Total A (excluding pass through)			$ 22.49			$ 25.49	**$ 3.00**	**13.32%**
Line Losses on Cost of Power	$ 0.1114	16	$ 1.83	$ 0.1114	15	$ 1.63	$ (0.19)	-10.53%
Total Deferral/Variance Account Rate Riders	-$ 0.0019	308	$ (0.59)	-$ 0.0015	308	$ (0.46)	$ 0.12	-21.05%
GA Rate Riders				$ -	308	$ -	$ -	
Low Voltage Service Charge	$ -	308	$ -		308	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 24.52**			**$ 27.45**	**$ 2.93**	**11.94%**
RTSR - Network	$ 0.0078	324	$ 2.53	$ 0.0077	323	$ 2.48	$ (0.05)	-1.81%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0061	324	$ 1.98	$ 0.0060	323	$ 1.94	$ (0.04)	-2.16%
Sub-Total C - Delivery (including Sub-Total B)			**$ 29.03**			**$ 31.87**	**$ 2.84**	**9.78%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	324	$ 1.17	$ 0.0036	323	$ 1.16	$ (0.01)	-0.53%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	324	$ 0.68	$ 0.0021	323	$ 0.68	$ (0.00)	-0.53%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
Ontario Electricity Support Program (OESP)	$ 0.0011	324	$ 0.36	$ 0.0011	323	$ 0.35	$ (0.00)	-0.41%
TOU - Off Peak	$ 0.0870	200	$ 17.42	$ 0.0870	200	$ 17.42	$ -	0.00%
TOU - Mid Peak	$ 0.1320	52	$ 6.91	$ 0.1320	52	$ 6.91	$ -	0.00%
TOU - On Peak	$ 0.1800	55	$ 9.98	$ 0.1800	55	$ 9.98	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 65.80**			**$ 68.62**	**$ 2.83**	**4.30%**
HST	13%		$ 8.55	13%		$ 8.92	$ 0.37	4.30%
Total Bill on TOU			**$ 74.35**			**$ 77.55**	**$ 3.20**	**4.30%**

Customer Class:	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0532
Proposed/Approved Loss Factor	1.0476

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 29.23	1	$ 29.23	$ 31.23	1	$ 31.23	$ 2.00	6.84%
Distribution Volumetric Rate	$ 0.0086	2000	$ 17.20	$ 0.0097	2000	$ 19.40	$ 2.20	12.79%
Fixed Rate Riders	$ 0.48	1	$ 0.48	$ -	1	$ -	$ (0.48)	-100.00%
Volumetric Rate Riders	$ -	2000	$ -	$ -	2000	$ -	$ -	
Sub-Total A (excluding pass through)			$ 46.91			$ 50.63	**$ 3.72**	**7.93%**
Line Losses on Cost of Power	$ 0.1114	106	$ 11.85	$ 0.1114	95	$ 10.60	$ (1.25)	-10.53%
Total Deferral/Variance Account Rate Riders	-$ 0.0019	2,000	$ (3.80)	-$ 0.0011	2,000	$ (2.20)	$ 1.60	-42.11%
GA Rate Riders				$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 55.75**			**$ 59.82**	**$ 4.07**	**7.30%**
RTSR - Network	$ 0.0069	2,106	$ 14.53	$ 0.0068	2,095	$ 14.25	$ (0.29)	-1.97%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0052	2,106	$ 10.95	$ 0.0051	2,095	$ 10.69	$ (0.27)	-2.44%
Sub-Total C - Delivery (including Sub-Total B)			**$ 81.24**			**$ 84.76**	**$ 3.52**	**4.33%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	2,106	$ 7.58	$ 0.0036	2,095	$ 7.54	$ (0.04)	-0.53%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	2,106	$ 4.42	$ 0.0021	2,095	$ 4.40	$ (0.02)	-0.53%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	2,106	$ 2.32	$ 0.0011	2,095	$ 2.30	$ (0.01)	-0.51%
TOU - Off Peak	$ 0.0870	1,300	$ 113.10	$ 0.0870	1,300	$ 113.10	$ -	0.00%
TOU - Mid Peak	$ 0.1320	340	$ 44.88	$ 0.1320	340	$ 44.88	$ -	0.00%
TOU - On Peak	$ 0.1800	360	$ 64.80	$ 0.1800	360	$ 64.80	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 332.59**			**$ 336.03**	**$ 3.44**	**1.03%**
HST	13%		$ 43.24	13%		$ 43.68	$ 0.45	1.03%
Total Bill on TOU			**$ 375.83**			**$ 379.72**	**$ 3.89**	**1.03%**

Customer Class:	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	32,400 kWh
Demand	60 kW
Current Loss Factor	1.0532
Proposed/Approved Loss Factor	1.0476

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 281.42	1	$ 281.42	$ 341.55	1	$ 341.55	$ 60.13	21.37%
Distribution Volumetric Rate	$ 2.4614	60	$ 147.68	$ 2.8791	60	$ 172.75	$ 25.06	16.97%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0066	60	$ 0.40	$ -	60	$ -	$ (0.40)	-100.00%
Sub-Total A (excluding pass through)			$ 429.50			$ 514.30	**$ 84.80**	**19.74%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.3118	60	$ (18.71)	-$ 0.2625	60	$ (15.75)	$ 2.96	-15.81%
GA Rate Riders				$ 0.0014	32,400	$ 45.36	$ 45.36	
Low Voltage Service Charge	$ -	60	$ -		60	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 410.79**			**$ 543.91**	**$ 133.11**	**32.40%**
RTSR - Network	$ 2.3625	60	$ 141.75	$ 2.3145	60	$ 138.87	$ (2.88)	-2.03%
RTSR - Connection and/or Line and Transformation Connection	$ 1.8027	60	$ 108.16	$ 1.9948	60	$ 119.69	$ 11.53	10.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 660.70**			**$ 802.46**	**$ 141.76**	**21.46%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	34,124	$ 122.85	$ 0.0036	33,942	$ 122.19	$ (0.65)	-0.53%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	34,124	$ 71.66	$ 0.0021	33,942	$ 71.28	$ (0.38)	-0.53%
Standard Supply Service Charge	$ 1.0000	0.25	$ 0.25	$ 1.0000	0.25	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	32,400	$ 226.80	$ 0.0070	32,400	$ 226.80	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	34,124	$ 37.54	$ 0.0011	33,942	$ 37.34	$ (0.20)	-0.53%
Average IESO Wholesale Market Price	$ 0.1071	34,124	$ 3,654.65	$ 0.1071	33,942	$ 3,635.21	$ (19.43)	-0.53%
Total Bill on Average IESO Wholesale Market Price			**$ 4,774.44**			**$ 4,895.54**	**$ 121.09**	**2.54%**
HST	13%		$ 620.68	13%		$ 636.42	$ 15.74	2.54%
Total Bill on Average IESO Wholesale Market Price			**$ 5,395.12**			**$ 5,531.95**	**$ 136.84**	**2.54%**

Customer Class:	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	1,091,088 kWh
Demand	3,648 kW
Current Loss Factor	1.0427
Proposed/Approved Loss Factor	1.0371

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 281.42	1	$ 281.42	$ 341.55	1	$ 341.55	$ 60.13	21.37%
Distribution Volumetric Rate	$ 2.4614	3612	$ 8,890.58	$ 2.8791	3612	$ 10,399.31	$ 1,508.73	16.97%
Transformer Allowance	$ (0.70)	3612	$ (2,528.40)	$ (0.70)	3612	$ (2,528.40)	$ -	0.00%
Volumetric Rate Riders	$ 0.0066	3612	$ 23.84	$ -	3612	$ -	$ (23.84)	-100.00%
Sub-Total A (excluding pass through)			$ 6,667.44			$ 8,212.46	**$ 1,545.02**	**23.17%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.3118	3,612	$ (1,126.22)	-$ 0.2625	3,612	$ (948.15)	$ 178.07	-15.81%
GA Rate Riders				$ 0.0014	1,080,177	$ 1,512.25	$ 1,512.25	
Low Voltage Service Charge	$ -	3,612	$ -		3,612	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 5,541.21**			**$ 8,776.56**	**$ 3,235.34**	**58.39%**
RTSR - Network	$ 2.3625	3,612	$ 8,533.35	$ 2.3145	3,612	$ 8,359.97	$ (173.38)	-2.03%
RTSR - Connection and/or Line and Transformation Connection	$ 1.8027	3,612	$ 6,511.35	$ 1.9948	3,612	$ 7,205.22	$ 693.87	10.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 20,585.92**			**$ 24,341.75**	**$ 3,755.83**	**18.24%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	1,137,677	$ 4,095.64	$ 0.0036	1,131,567	$ 4,073.64	$ (22.00)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	1,137,677	$ 2,389.12	$ 0.0021	1,131,567	$ 2,376.29	$ (12.83)	-0.54%
Standard Supply Service Charge	$ 1.0000	0.25	$ 0.25	$ 1.0000	0.25	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	1,080,177	$ 7,561.24	$ 0.0070	1,080,177	$ 7,561.24	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	1,137,677	$ 1,251.44	$ 0.0011	1,131,567	$ 1,244.72	$ (6.72)	-0.54%
Average IESO Wholesale Market Price	$ 0.1077	1,137,677	$ 122,527.86	$ 0.1077	1,131,567	$ 121,869.81	$ (658.06)	-0.54%
Total Bill on Average IESO Wholesale Market Price			**$ 158,411.47**			**$ 161,467.70**	**$ 3,056.23**	**1.93%**
HST	13%		$ 20,593.49	13%		$ 20,990.80	$ 397.31	1.93%
Total Bill on Average IESO Wholesale Market Price			**$ 179,004.97**			**$ 182,458.50**	**$ 3,453.54**	**1.93%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	150 kWh
Demand	- kW
Current Loss Factor	1.0532
Proposed/Approved Loss Factor	1.0476

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 11.93	1	$ 11.93	$ 10.52	1	$ 10.52	$ (1.41)	-11.82%
Distribution Volumetric Rate	$ 0.0079	150	$ 1.19	$ 0.0069	150	$ 1.04	$ (0.15)	-12.66%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0001	150	$ 0.02	$ -	150	$ -	$ (0.02)	-100.00%
Sub-Total A (excluding pass through)			$ 13.13			$ 11.56	**$ (1.58)**	**-12.00%**
Line Losses on Cost of Power	$ 0.1114	8	$ 0.89	$ 0.1114	7	$ 0.80	$ (0.09)	-10.53%
Total Deferral/Variance Account Rate Riders	-$ 0.0019	150	$ (0.29)	-$ 0.0015	150	$ (0.23)	$ 0.06	-21.05%
GA Rate Riders				$ -	150	$ -	$ -	
Low Voltage Service Charge	$ -	150	$ -		150	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 13.73**			**$ 12.13**	**$ (1.61)**	**-11.71%**
RTSR - Network	$ 0.0069	158	$ 1.09	$ 0.0068	157	$ 1.07	$ (0.02)	-1.97%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0052	158	$ 0.82	$ 0.0051	157	$ 0.80	$ (0.02)	-2.44%
Sub-Total C - Delivery (including Sub-Total B)			**$ 15.65**			**$ 14.00**	**$ (1.65)**	**-10.55%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	158	$ 0.57	$ 0.0036	157	$ 0.57	$ (0.00)	-0.53%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	158	$ 0.33	$ 0.0021	157	$ 0.33	$ (0.00)	-0.53%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	158	$ 0.17	$ 0.0011	157	$ 0.17	$ (0.00)	-0.54%
TOU - Off Peak	$ 0.0870	98	$ 8.48	$ 0.0870	98	$ 8.48	$ -	0.00%
TOU - Mid Peak	$ 0.1320	26	$ 3.37	$ 0.1320	26	$ 3.37	$ -	0.00%
TOU - On Peak	$ 0.1800	27	$ 4.86	$ 0.1800	27	$ 4.86	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 34.73**			**$ 33.07**	**$ (1.66)**	**-4.77%**
HST	13%		$ 4.51	13%		$ 4.30	$ (0.22)	-4.77%
Total Bill on TOU			**$ 39.24**			**$ 37.37**	**$ (1.87)**	**-4.77%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	120	kWh
Demand	0.3	kW
Current Loss Factor	1.0532	
Proposed/Approved Loss Factor	1.0476	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.69	1	$ 2.69	$ 3.78	1	$ 3.78	$ 1.09	40.52%
Distribution Volumetric Rate	$ 6.0251	0.3	$ 1.81	$ 8.4360	0.3	$ 2.53	$ 0.72	40.01%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0297	0.3	$ 0.01	$ -	0.3	$ -	$ (0.01)	-100.00%
Sub-Total A (excluding pass through)			$ 4.51			$ 6.31	**$ 1.80**	**40.04%**
Line Losses on Cost of Power	$ 0.1114	6	$ 0.71	$ 0.1114	6	$ 0.64	$ (0.07)	-10.53%
Total Deferral/Variance Account Rate Riders	-$ 0.7090	0	$ (0.21)	-$ 0.6235	0	$ (0.19)	$ 0.03	-12.06%
GA Rate Riders				$ -	120	$ -	$ -	
Low Voltage Service Charge	$ -	0	$ -		0	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 5.00**			**$ 6.76**	**$ 1.76**	**35.07%**
RTSR - Network	$ 2.2003	0.3	$ 0.66	$ 2.1670	0.3	$ 0.65	$ (0.01)	-1.51%
RTSR - Connection and/or Line and Transformation Connection	$ 1.6792	0.3	$ 0.50	$ 1.6448	0.3	$ 0.49	$ (0.01)	-2.05%
Sub-Total C - Delivery (including Sub-Total B)			**$ 6.17**			**$ 7.90**	**$ 1.73**	**28.12%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	126	$ 0.45	$ 0.0036	126	$ 0.45	$ (0.00)	-0.53%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	126	$ 0.27	$ 0.0021	126	$ 0.26	$ (0.00)	-0.53%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	120	$ 0.84	$ 0.0070	120	$ 0.84	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	126	$ 0.14	$ 0.0011	126	$ 0.14	$ -	0.00%
TOU - Off Peak	$ 0.0870	78	$ 6.79	$ 0.0870	78	$ 6.79	$ -	0.00%
TOU - Mid Peak	$ 0.1320	20	$ 2.69	$ 0.1320	20	$ 2.69	$ -	0.00%
TOU - On Peak	$ 0.1800	22	$ 3.89	$ 0.1800	22	$ 3.89	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 21.48**			**$ 23.22**	**$ 1.73**	**8.06%**
HST	13%		$ 2.79	13%		$ 3.02	$ 0.23	8.06%
Total Bill on TOU			**$ 24.28**			**$ 26.23**	**$ 1.96**	**8.06%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	16 kWh
Demand	0.044 kW
Current Loss Factor	1.0532
Proposed/Approved Loss Factor	1.0476

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1.99	1	$ 1.99	$ 0.62	1	$ 0.62	$ (1.37)	-68.84%
Distribution Volumetric Rate	$ 8.3543	0.044	$ 0.37	$ 2.5797	0.044	$ 0.11	$ (0.25)	-69.12%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0533	0.044	$ 0.00	$ -	0.044	$ -	$ (0.00)	-100.00%
Sub-Total A (excluding pass through)			$ 2.36			$ 0.73	**$ (1.63)**	**-68.92%**
Line Losses on Cost of Power	$ 0.1077	1	$ 0.09	$ 0.1077	1	$ 0.08	$ (0.01)	-10.53%
Total Deferral/Variance Account Rate Riders	-$ 0.4104	0.044	$ (0.02)	-$ 0.5932	0.044	$ (0.03)	$ (0.01)	44.54%
GA Rate Riders				$ 0.0014	16	$ 0.02	$ 0.02	
Low Voltage Service Charge	$ -	0	$ -		0	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2.43**			**$ 0.81**	**$ (1.62)**	**-66.64%**
RTSR - Network	$ 2.1955	0.044	$ 0.10	$ 2.1623	0.044	$ 0.10	$ (0.00)	-1.51%
RTSR - Connection and/or Line and Transformation Connection	$ 1.6755	0.044	$ 0.07	$ 1.6411	0.044	$ 0.07	$ (0.00)	-2.05%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2.60**			**$ 0.98**	**$ (1.62)**	**-62.40%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	17	$ 0.06	$ 0.0036	17	$ 0.06	$ (0.00)	-0.53%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	17	$ 0.04	$ 0.0021	17	$ 0.04	$ (0.00)	-0.53%
Standard Supply Service Charge	$ 1.0000	0.25	$ 0.25	$ 1.0000	0.25	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	16	$ 0.11	$ 0.0070	16	$ 0.11	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	17	$ 0.02	$ 0.0011	17	$ 0.02	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1077	16	$ 1.72	$ 0.1077	16	$ 1.72	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 4.80**			**$ 3.18**	**$ (1.63)**	**-33.83%**
HST	13%		$ 0.62	13%		$ 0.41	$ (0.21)	-33.83%
Total Bill on Average IESO Wholesale Market Price			**$ 5.43**			**$ 3.59**	**$ (1.84)**	**-33.83%**

APPENDIX C
REVISED 2017 EDDVAR WORKFORM

Ontario Energy Board

2017 Deferral/Variance Account Workform

Version 2.8

Utility Name	Welland Hydro Electric System Corp.
Service Territory	*Welland, Ontario*
Assigned EB Number	EB-2016-0110
Name of Contact and Title	Wayne Armstrong - Director of Finance & COO
Phone Number	905-732-1381 Ext 234
Email Address	warmstrong@wellandhydro.com

General Notes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Account Descriptions	Account Number	Transactions[1] Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments[2] during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments[2] during 2012	Closing Interest Amounts as of Dec-31-12
		2012								
Group 1 Accounts										
LV Variance Account	1550				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551									
RSVA - Wholesale Market Service Charge[10]	1580			-$951,150	-$951,150	$0			-$18,042	-$18,042
Variance WMS – Sub-account CBR Class A[10]	1580									
Variance WMS – Sub-account CBR Class B[10]	1580									
RSVA - Retail Transmission Network Charge	1584			$380,414	$380,414	$0			$4,387	$4,387
RSVA - Retail Transmission Connection Charge	1586			$190,333	$190,333	$0			$1,072	$1,072
RSVA - Power (excluding Global Adjustment)	1588			-$427,871	-$427,871	$0			-$3,658	-$3,658
RSVA - Global Adjustment	1589			$470,582	$470,582	$0			$9,091	$9,091
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595				$0	$0			-$6,731	-$6,731
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595			-$32,927	-$32,927	$0			-$7,848	-$7,848
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595			-$994,227	-$994,227	$0			-$10,507	-$10,507
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited										
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	-$1,364,846	-$1,364,846	$0	$0	$0	-$32,236	-$32,236
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	-$1,835,428	-$1,835,428	$0	$0	$0	-$41,327	-$41,327
RSVA - Global Adjustment	**1589**	$0	$0	$470,582	$470,582	$0	$0	$0	$9,091	$9,091
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$44,673	$44,673	$0			$1,288	$1,288
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other[4]	1508				$0	$0				$0
Retail Cost Variance Account - Retail	1518				$0	$0				$0
Misc. Deferred Debits	1525				$0	$0				$0
Retail Cost Variance Account - STR	1548				$0	$0				$0
Board-Approved CDM Variance Account	1567				$0	$0				$0
Extra-Ordinary Event Costs	1572				$0	$0				$0
Deferred Rate Impact Amounts	1574				$0	$0				$0
RSVA - One-time	1582				$0	$0				$0
Other Deferred Credits	2425				$0	$0				$0
Group 2 Sub-Total		$0	$0	$44,673	$44,673	$0	$0	$0	$1,288	$1,288
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		$0	$0	-$1,320,173	-$1,320,173	$0	$0	$0	-$30,948	-$30,948

Account Descriptions	Account Number	2012 Transactions[1] Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments[2] during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments[2] during 2012	Closing Interest Amounts as of Dec-31-12
LRAM Variance Account[12]	**1568**				$0	$0				$0
Total including Account 1568		$0	$0	-$1,320,173	-$1,320,173	$0	$0	$0	-$30,948	-$30,948
Renewable Generation Connection Capital Deferral Account[9]	1531				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533				$0	$0				$0
Smart Grid Capital Deferral Account	1534				$0	$0				$0
Smart Grid OM&A Deferral Account	1535				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555				$0	$0				$0
Smart Meter OM&A Variance[5]	1556				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557									
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576				$0					

Account Descriptions	Account Number	2013									
		Opening Principal Amounts as of Jan-1-13	Transactions[1] Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments[2] during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments[1] during 2013	Closing Interest Amounts as of Dec-31-13
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$0	$12,286			$12,286	$0	$198			$198
RSVA - Wholesale Market Service Charge[10]	1580	-$951,150	-$240,570	-$415,650		-$776,070	-$18,042	-$13,149	-$12,447		-$18,744
Variance WMS – Sub-account CBR Class A[10]	1580										
Variance WMS – Sub-account CBR Class B[10]	1580										
RSVA - Retail Transmission Network Charge	1584	$380,414	-$84,402	$249,250		$46,762	$4,387	$2,382	$5,614		$1,155
RSVA - Retail Transmission Connection Charge	1586	$190,333	$4,842	$135,550		$59,625	$1,072	$1,233	$2,690		-$385
RSVA - Power (excluding Global Adjustment)	1588	-$427,871	$514,405	$306,835		-$220,301	-$3,658	-$11,003	$6,524		-$21,185
RSVA - Global Adjustment	1589	$470,582	$253,642	$112,037		$612,187	$9,091	$8,858	$5,907		$12,042
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	-$6,731		-$6,731		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	-$32,927		-$32,927		$0	-$7,848	-$161	-$1,164		-$6,845
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	-$994,227	$683,246			-$310,981	-$10,507	-$9,976			-$20,483
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	$0	-$196,732	-$833,065		$636,333	$0	$6,375			$6,375
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$1,364,846	$946,717	-$477,970	$0	$59,841	-$32,236	-$15,243	$393	$0	-$47,872
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$1,835,428	$693,075	-$590,007	$0	-$552,346	-$41,327	-$24,101	-$5,514	$0	-$59,914
RSVA - Global Adjustment	1589	$470,582	$253,642	$112,037	$0	$612,187	$9,091	$8,858	$5,907	$0	$12,042
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$44,673	$4,265	$44,673		$4,265	$1,288	$282	$1,489		$81
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other[4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$44,673	$4,265	$44,673	$0	$4,265	$1,288	$282	$1,489	$0	$81
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$1,320,173	$950,982	-$433,297	$0	$64,106	-$30,948	-$14,961	$1,882	$0	-$47,791

Account Descriptions	Account Number	2013									
		Opening Principal Amounts as of Jan-1-13	Transactions[1] Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments[2] during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments[2] during 2013	Closing Interest Amounts as of Dec-31-13
LRAM Variance Account[12]	**1568**	$0				$0	$0				$0
Total including Account 1568		-$1,320,173	$950,982	-$433,297	$0	$64,106	-$30,948	-$14,961	$1,882	$0	-$47,791
Renewable Generation Connection Capital Deferral Account[9]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576	$0				$0					

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions[1] Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments[2] during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments[2] during 2014	Closing Interest Amounts as of Dec-31-14
		2014									
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$12,286	-$3,933			$8,353	$198	$165			$363
RSVA - Wholesale Market Service Charge[10]	1580	-$776,070	-$52,249	-$535,500		-$292,819	-$18,744	-$4,563	-$16,091		-$7,216
Variance WMS – Sub-account CBR Class A[10]	1580										
Variance WMS – Sub-account CBR Class B[10]	1580										
RSVA - Retail Transmission Network Charge	1584	$46,762	-$83,356	$131,164		-$167,758	$1,155	-$1,452	$1,343		-$1,640
RSVA - Retail Transmission Connection Charge	1586	$59,625	$35,601	$54,783		$40,443	-$385	$502	-$544		$661
RSVA - Power (excluding Global Adjustment)	1588	-$220,301	-$508,498	-$734,706		$5,907	-$21,185	-$11,816	-$24,582		-$8,419
RSVA - Global Adjustment	1589	$612,187	$152,706	$358,545		$406,348	$12,042	$4,040	$10,211		$5,871
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	$0				$0	-$6,845		-$6,845		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	-$310,981	$234,785			-$76,196	-$20,483	-$1,651			-$22,134
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	$636,333	-$275,578			$360,755	$6,375	$7,441			$13,816
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	$0	$467,336	$762,222		-$294,886	$0	-$4,289			-$4,289
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$59,841	-$33,186	$36,508	$0	-$9,853	-$47,872	-$11,623	-$36,508	$0	-$22,987
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$552,346	-$185,892	-$322,037	$0	-$416,201	-$59,914	-$15,663	-$46,719	$0	-$28,858
RSVA - Global Adjustment	1589	$612,187	$152,706	$358,545	$0	$406,348	$12,042	$4,040	$10,211	$0	$5,871
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$4,265				$4,265	$81	$62			$143
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other[4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$4,265	$0	$0	$0	$4,265	$81	$62	$0	$0	$143
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		$64,106	-$33,186	$36,508	$0	-$5,588	-$47,791	-$11,561	-$36,508	$0	-$22,844

Account Descriptions	Account Number	2014 Opening Principal Amounts as of Jan-1-14	Transactions[1] Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments[1] during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments[1] during 2014	Closing Interest Amounts as of Dec-31-14
LRAM Variance Account[12]	**1568**	$0				$0	$0				$0
Total including Account 1568		$64,106	-$33,186	$36,508	$0	-$5,588	-$47,791	-$11,561	-$36,508	$0	-$22,844
Renewable Generation Connection Capital Deferral Account[9]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576	$0				$0					

Account Descriptions	Account Number	2015									
		Opening Principal Amounts as of Jan-1-15	Transactions[1] Debit/ (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments[2] during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments[1] during 2015	Closing Interest Amounts as of Dec-31-15
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$8,353	-$2,118			$6,235	$363	$99			$462
RSVA - Wholesale Market Service Charge[10]	1580	-$292,819	-$824,851	-$240,570		-$877,100	-$7,216	-$5,052	-$7,368		-$4,900
Variance WMS – Sub-account CBR Class A[10]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[10]	1580	$0	$99,240			$99,240	$0				$0
RSVA - Retail Transmission Network Charge	1584	-$167,758	-$148,772	-$84,402		-$232,128	-$1,640	-$2,660	-$1,843		-$2,457
RSVA - Retail Transmission Connection Charge	1586	$40,443	-$70,493	$4,842		-$34,892	$661	-$45	$254		$362
RSVA - Power (excluding Global Adjustment)	1588	$5,907	$504,522	$514,430		-$4,001	-$8,419	-$5,619	$13,480		-$27,518
RSVA - Global Adjustment	1589	$406,348	$200,038	$253,616		$352,770	$5,871	$2,254	$6,802		$1,323
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	-$76,196				-$76,196	-$22,134	-$873			-$23,007
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	$360,755	-$157,762			$202,993	$13,816	$3,312			$17,128
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	-$294,886	$236,321			-$58,565	-$4,289	-$918			-$5,207
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0	-$292,380	-$459,241		$166,861	$0	$1,998			$1,998
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$9,853	-$456,255	-$11,325	$0	-$454,783	-$22,987	-$7,504	$11,325	$0	-$41,816
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$416,201	-$656,293	-$264,941	$0	-$807,553	-$28,858	-$9,758	$4,523	$0	-$43,139
RSVA - Global Adjustment	1589	$406,348	$200,038	$253,616	$0	$352,770	$5,871	$2,254	$6,802	$0	$1,323
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$4,265	$7,500			$11,765	$143	$73			$216
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other[4]	1508	$0	$450			$450	$0	$1			$1
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$4,265	$7,950	$0	$0	$12,215	$143	$74	$0	$0	$217
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$5,588	-$448,305	-$11,325	$0	-$442,568	-$22,844	-$7,430	$11,325	$0	-$41,599

Account Descriptions	Account Number	2015 Opening Principal Amounts as of Jan-1-15	Transactions[1] Debit/ (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments[2] during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments[1] during 2015	Closing Interest Amounts as of Dec-31-15
LRAM Variance Account[12]	**1568**	$0	$34,250			$34,250	$0	$715			$715
Total including Account 1568		-$5,588	-$414,055	-$11,325	$0	-$408,318	-$22,844	-$6,715	$11,325	$0	-$40,884
Renewable Generation Connection Capital Deferral Account[9]	1531	$0	$86,187			$86,187	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0	$9,968			$9,968	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	$0	$35,287			$35,287					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576	$0				$0					

		2016				Projected Interest on Dec-31-15 Balances					2.1.7 RRR	
Account Descriptions	Account Number	Principal Disposition during 2016 - instructed by OEB	Interest Disposition during 2016 - instructed by OEB	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Closing Interest Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Projected Interest from Jan 1, 2016 to December 31, 2016 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Projected Interest from January 1, 2017 to April 30, 2017 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Total Interest		Total Claim	As of Dec 31-15	Variance RRR vs. 2015 Balance *(Principal + Interest)*
Group 1 Accounts												
LV Variance Account	1550			$0	$0			$0		$0.00		$0
Smart Metering Entity Charge Variance Account	1551	$8,353	$493	-$2,118	-$31	-$23	-$8	-$62		-$2,180.00	$6,697	$0
RSVA - Wholesale Market Service Charge[10]	1580	-$52,249	-$663	-$824,851	-$4,237	-$9,073	-$3,024	-$16,335		-$841,185.81	-$782,760	$99,240
Variance WMS – Sub-account CBR Class A[10]	1580			$0	$0			$0	Check to Dispose of Account	$0.00		$0
Variance WMS – Sub-account CBR Class B[10]	1580			$99,240	$0	$1,092	$364	$1,456	Check to Dispose of Account	$100,695.52		-$99,240
RSVA - Retail Transmission Network Charge	1584	-$83,356	-$1,097	-$148,772	-$1,360	-$1,636	-$545	-$3,541		-$152,313.00	-$234,585	$0
RSVA - Retail Transmission Connection Charge	1586	$35,601	$962	-$70,493	-$600	-$775	-$258	-$1,633		-$72,126.00	-$34,530	$0
RSVA - Power (excluding Global Adjustment)	1588	-$508,523	-$29,828	$504,522	$2,310	$5,550	$1,850	$9,710		$514,232.00	-$31,519	$0
RSVA - Global Adjustment	1589	$152,732	$1,450	$200,038	-$127	$2,200	$733	$2,806		$202,844.00	$354,093	$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595			$0	$0			$0	Check to Dispose of Account	$0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595			$0	$0			$0	Check to Dispose of Account	$0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595			$0	$0			$0	Check to Dispose of Account	$0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	-$76,196	-$23,007	$0	$0			$0	Check to Dispose of Account	$0.00	-$99,203	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	$172,968	$11,718	$30,025	$5,410	$330	$110	$5,850	Check to Dispose of Account	$35,875.00	$220,121	$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595			-$58,565	-$5,207	-$645	-$216	-$6,068	Check to Dispose of Account	-$64,633.00	-$63,772	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595			$166,861	$1,998			$1,998	Check to Dispose of Account	$0.00	$168,859	$0
Not to be disposed of unless rate rider has expired and balance has been audited												
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$350,670	-$39,972	-$104,113	-$1,844	-$2,981	-$995	-$5,819		-$278,791.29	-$496,599	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$503,402	-$41,422	-$304,151	-$1,717	-$5,181	-$1,728	-$8,625		-$481,635.29	-$850,692	$0
RSVA - Global Adjustment	1589	$152,732	$1,450	$200,038	-$127	$2,200	$733	$2,806		$202,844.00	$354,093	$0
Group 2 Accounts												
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$14,250		$26,015	$216	$129	$43	$388		$26,403.00	$11,981	$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0	$0			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508			$0	$0			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Other [4]	1508			$450	$1			$1	Check to Dispose of Account	$0.00	$451	$0
Retail Cost Variance Account - Retail	1518			$0	$0			$0		$0.00		$0
Misc. Deferred Debits	1525			$0	$0			$0	Check to Dispose of Account	$0.00		$0
Retail Cost Variance Account - STR	1548			$0	$0			$0		$0.00		$0
Board-Approved CDM Variance Account	1567			$0	$0			$0		$0.00		$0
Extra-Ordinary Event Costs	1572			$0	$0			$0		$0.00		$0
Deferred Rate Impact Amounts	1574			$0	$0			$0		$0.00		$0
RSVA - One-time	1582			$0	$0			$0		$0.00		$0
Other Deferred Credits	2425			$0	$0			$0	Check to Dispose of Account	$0.00		$0
Group 2 Sub-Total		-$14,250	$0	$26,465	$217	$129	$43	$389		$26,403.00	$12,432	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0	$0			$0		$0.00		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$0	$0			$0		$0.00		$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$364,920	-$39,972	-$77,648	-$1,627	-$2,852	-$952	-$5,430		-$252,388.29	-$484,167	$0

Account Descriptions	Account Number	2016 Principal Disposition during 2016 - instructed by OEB	Interest Disposition during 2016 - instructed by OEB	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Closing Interest Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Projected Interest on Dec-31-15 Balances Projected Interest from Jan 1, 2016 to December 31, 2016 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Projected Interest from January 1, 2017 to April 30, 2017 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Total Interest		Total Claim	2.1.7 RRR As of Dec 31-15	Variance RRR vs. 2015 Balance *(Principal + Interest)*
LRAM Variance Account[12]	1568	$20,454	$511	$13,796	$204	$151	$51	$406		$14,202.00	$34,965	$0
Total including Account 1568		-$344,466	-$39,461	-$63,852	-$1,423	-$2,701	-$901	-$5,024		-$238,186.29	-$449,202	$0
Renewable Generation Connection Capital Deferral Account[9]	1531	$86,187		$0	$0			$0		$0.00	$86,187	$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	-$12,737		$22,705	$0			$0		$22,705.00	$9,968	$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0	$0			$0		$0.00		$0
Smart Grid Capital Deferral Account	1534			$0	$0			$0		$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0	$0			$0		$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0	$0			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555			$0	$0			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	-$172,968	-$11,718	$172,968	$11,718			$11,718		$184,686.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555			$0	$0			$0		$0.00		$0
Smart Meter OM&A Variance[5]	1556			$0	$0			$0		$0.00		$0
Meter Cost Deferral Account (MIST Meters)[11]	1557			$0	$0			$0		$0.00		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	-$46,499		$81,786					☑Check to Dispose of Account	$81,786.00	$35,287	$0
Accounting Changes Under CGAAP Balance + Return Component[6]	1576			$0					☑Check to Dispose of Account	$0.00		$0

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2017 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2015 Balance (*Principal + Interest*)	Explanation
3	RSVA - Wholesale Market Service Charge10	1580	$ 99,240.00	RRR Includes Sub-Account
3.2	Variance WMS – Sub-account CBR Class B10	1580	$ (99,240.00)	RRR Includes Sub-Account

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2017 Deferral/Variance Account Workform

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.

			A		B		
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh**	**Total Metered kW**	**Metered kWh for Non-RPP Customers**	**Estimated Metered kW for Non-RPP Customers**	**Distribution Revenue**
RESIDENTIAL	kWh	21,025	158,180,520		9,182,152	-	6,394,155
GENERAL SERVICE LESS THAN 50 KW	kWh	1,777	51,585,867		7,707,658	-	1,056,712
GENERAL SERVICE 50 TO 4,999 KW	kW	154	134,086,770	377,726	127,360,285	358,777	1,316,365
UNMETERED SCATTERED LOAD	kWh	261	963,825		177,292	-	45,027
SENTINEL LIGHTING	kW	509	749,437	2,061	23,169	64	28,840
STREET LIGHTING	kW	6,856	1,286,433	3,582	1,582,470	4,406	193,638
						-	
						-	
						-	
						-	
						-	
						-	
						-	
						-	
						-	
						-	
						-	
						-	
						-	
						-	
Total		**30,582**	**346,852,852**	**383,369**	**146,033,026**	**363,247**	**$ 9,034,737**

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erral/Variance Account Workform

If a Class B customer switched into Class A during the 2015 rate year, click this check box: ☑

Identify the total consumption for former Class B customers prior to becoming Class A customers (i.e. Jan 1. to June 30, 2015) in column Q.

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.

	C		D=A-C		E		F =B-C-E
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Metered kWh for Wholesale Market Participants (WMP)**	**Metered kW for Wholesale Market Participants (WMP)**	**Total Metered kWh less WMP consumption** *(if applicable)*	**Total Metered kW less WMP consumption** *(if applicable)*	**Metered kWh for any Class A Customers in 2015 (partial or full year) (if applicable)***	**Metered kWh Consumption for New Class A customer(s) in the period prior to becoming Class A (i.e. Jan. 1 - June 30, 2015)**	**Metered Consumption kWh for Current Class B Customers (Non-RPP consumption LESS WMP, Class A and new Class A's former Class B consumption, if applicable)**
RESIDENTIAL			158,180,520	-			9,182,152
GENERAL SERVICE LESS THAN 50 KW			51,585,867	-			7,707,658
GENERAL SERVICE 50 TO 4,999 KW	3,164,185	5,727	130,922,585	371,999			124,196,100
UNMETERED SCATTERED LOAD			963,825	-			177,292
SENTINEL LIGHTING			749,437	2,061			23,169
STREET LIGHTING			1,286,433	3,582			1,582,470
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
			-	-			-
Total	**3,164,185**	**5,727**	**343,688,667**	**377,642**	**-**		**142,868,841**

Ontario Energy Board

erral/Variance Account Workform

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.

Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	1595 Recovery Share Proportion (2014) [1]	1595 Recovery Share Proportion (2015) [1]	1568 LRAM Variance Account Class Allocation[3] ($ amounts)	Number of Customers for Residential and GS<50 classes[2]
RESIDENTIAL	53%		(18,701)	21,025
GENERAL SERVICE LESS THAN 50 KW	18%		5,320	1,777
GENERAL SERVICE 50 TO 4,999 KW	29%		29,263	
UNMETERED SCATTERED LOAD	0%		(272)	
SENTINEL LIGHTING	0%		(473)	
STREET LIGHTING	0%		(935)	
Total		0%	$ 14,202	

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2017 Deferral/Variance Account Workform

		Amounts from Sheet 2	Allocator	RESIDENTIAL	GENERAL SERVICE LESS THAN 50 KW	GENERAL SERVICE 50 TO 4,999 KW	UNMETERED SCATTERED LOAD	SENTINEL LIGHTING	STREET LIGHTING
LV Variance Account	1550	0	kWh	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	(2,180)	# of Customers	(2,010)	(170)	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(740,490)	kWh	(340,806)	(111,144)	(282,078)	(2,077)	(1,615)	(2,772)
RSVA - Retail Transmission Network Charge	1584	(152,313)	kWh	(69,462)	(22,653)	(58,881)	(423)	(329)	(565)
RSVA - Retail Transmission Connection Charge	1586	(72,126)	kWh	(32,893)	(10,727)	(27,883)	(200)	(156)	(268)
RSVA - Power (excluding Global Adjustment)	1588	514,232	kWh	236,672	77,184	195,888	1,442	1,121	1,925
RSVA - Global Adjustment	1589	202,844	Non-RPP kWh	13,037	10,943	176,333	252	33	2,247
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	35,875	kWh	16,361	5,336	13,869	100	78	133
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(64,633)	%	(34,126)	(11,375)	(18,614)	(259)	(194)	(129)
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(481,635)**		**(226,264)**	**(73,550)**	**(177,699)**	**(1,417)**	**(1,095)**	**(1,676)**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	26,403	kWh	12,041	3,927	10,207	73	57	98
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	0	kWh	0	0	0	0	0	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	0	kWh	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0
Total of Group 2 Accounts		**26,403**		**12,041**	**3,927**	**10,207**	**73**	**57**	**98**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	kWh	0	0	0	0	0	0
Total of Account 1592		**0**		**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account (Enter dollar amount for each class)	1568	**14,202**		(18,701)	5,320	29,263	(272)	(473)	(935)
(Account 1568 - total amount allocated to classes)		14,202							
Variance		**0**							
Renewable Generation Connection OM&A Deferral Account	1532	**22,705**	kWh	10,355	3,377	8,777	63	49	84
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(255,442)**		**(122,130)**	**(39,590)**	**(91,510)**	**(783)**	**(601)**	**(829)**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(226,258)**		**(104,134)**	**(33,960)**	**(86,189)**	**(635)**	**(493)**	**(847)**
Balance of Account 1589 Allocated to Non-WMPs		**202,844**		**13,037**	**10,943**	**176,333**	**252**	**33**	**2,247**
Group 2 Accounts (including 1592, 1532)		**49,108**		**22,395**	**7,304**	**18,984**	**136**	**106**	**182**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	81,786	kWh	37,298	12,164	31,617	227	177	303
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**81,786**		**37,298**	**12,164**	**31,617**	**227**	**177**	**303**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$6.63
1589/total kwh	$0.0006

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2017 Deferral/Variance Account Workform

This tab allocates the GA balance to former Class B customers who contributed to the current GA balance but are now Class A customers. The tables below calculate specific amounts for each customer who made the change. Consistent with both decisions for 2016 rates and EDDVAR, distributors are generally expected to settle the amount through 12 equal adjustments to bills. A one-time settlement is acceptable if the affected customer has expressed a clear preference for this approach. (see Filing Requirements section 2.9.5.1)

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Year of Group 1 Account Balance Last Disposed	**2014**	**(e.g. If in the 2015 EDR process, you received approval to dispose the GA variance account balance as of December 31, 2013, please enter 2013 in cell B16.)**

Allocation of total Non-RPP consumption (kWh) between Class B and New Class A (Former Class B) customers

		Total	2015
Total Class B Consumption for Years Since Last Dispposition (Non-RPP consumption LESS WMP and Class A)	A	113,773,167	113,773,167
New Class A Customer(s)' Former Class B Consumption	B	-	-
Portion of Consumption of Former Class B Customers	C=B/A	**0.00%**	

Allocation of Total GA Balance $

Total GA Balance	D	$ 202,844
New Class A Customer(s)' Former Class B Portion of GA Balance	E=C*D	$ -
GA Balance to be disposed to Current Class B Customers	F=D-E	$ 202,844

Allocation of GA Balances to Former Class B Customers

# of Former Class B customer(s)		0				
Customer		**Total Metered kWh Consumption for each new Class A customer for the period prior to becoming Class A**	**Metered kWh Consumption for each new Class A customer for the period prior to becoming Class A in 2015**	**% of kWh**	**Customer specific GA allocation for the period prior to becoming Class A**	**Monthly Equal Payments**

Ontario Energy Board

2017 Deferral/Variance Account Workform

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

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL	kWh	158,180,520	-$ 122,130	- 0.0008	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	51,585,867	-$ 39,590	- 0.0008	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	kW	377,726	-$ 91,510	- 0.2423	$/kW
UNMETERED SCATTERED LOAD	kWh	963,825	-$ 783	- 0.0008	$/kWh
SENTINEL LIGHTING	kW	2,061	-$ 601	- 0.2918	$/kW
STREET LIGHTING	kW	3,582	-$ 829	- 0.2313	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			-$ 255,442		

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL	kWh	158,180,520	-$ 104,134	- 0.0007	$/kWh

GENERAL SERVICE LESS THAN 50 KW	kWh	51,585,867	-$ 33,960	- 0.0007	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	kW	371,999	-$ 86,189	- 0.2317	$/kW
UNMETERED SCATTERED LOAD	kWh	963,825	-$ 635	- 0.0007	$/kWh
SENTINEL LIGHTING	kW	2,061	-$ 493	- 0.2394	$/kW
STREET LIGHTING	kW	3,582	-$ 847	- 0.2364	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 226,258**		

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Balance of RSVA - Power - Global Adjustment	Rate Rider for RSVA - Power - Global Adjustment	
RESIDENTIAL	kWh	9,182,152	$ 13,037	0.0014	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	7,707,658	$ 10,943	0.0014	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	kWh	124,196,100	$ 176,333	0.0014	$/kWh
UNMETERED SCATTERED LOAD	kWh	177,292	$ 252	0.0014	$/kWh
SENTINEL LIGHTING	kWh	23,169	$ 33	0.0014	$/kWh
STREET LIGHTING	kWh	1,582,470	$ 2,247	0.0014	$/kWh
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**$ 202,844**		

Rate riders for Global Adjustm
basis of kWh f

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Balance of Group 2 Accounts	Rate Rider for RSVA - Power - Global Adjustment	
RESIDENTIAL	# of Customers	21,025	$ 22,395	$ 0.09	per customer per month
GENERAL SERVICE LESS THAN 50 KW	kWh	51,585,867	$ 7,304	$ 0.0001	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	kW	377,726	$ 18,984	$ 0.0503	$/kW
UNMETERED SCATTERED LOAD	kWh	963,825	$ 136	$ 0.0001	$/kWh
SENTINEL LIGHTING	kW	2,061	$ 106	$ 0.0515	$/kW
STREET LIGHTING	kW	3,582	$ 182	$ 0.0508	$/kW
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
Total			$ 49,108		

As per regar distributi group 2 ac

Rate Rider Calculation for Accounts 1575 and 1576

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

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576	
RESIDENTIAL	# of Customers	21,025	$ 37,298	0.1478	per customer per month
GENERAL SERVICE LESS THAN 50 KW	kWh	51,585,867	$ 12,164	0.0002	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	kW	377,726	$ 31,617	0.0837	$/kW
UNMETERED SCATTERED LOAD	kWh	963,825	$ 227	0.0002	$/kWh
SENTINEL LIGHTING	kW	2,061	$ 177	0.0857	$/kW
STREET LIGHTING	kW	3,582	$ 303	0.0847	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	

As p rega distribu group 2 per

		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			$ 81,786	

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	kWh	158,180,520	-$ 18,701	- 0.0001	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	51,585,867	$ 5,320	0.0001	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	kW	377,726	$ 29,263	0.0775	$/kW
UNMETERED SCATTERED LOAD	kWh	963,825	-$ 272	- 0.0003	$/kWh
SENTINEL LIGHTING	kW	2,061	-$ 473	- 0.2295	$/kW
STREET LIGHTING	kW	3,582	-$ 935	- 0.2610	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			$ 14,202		

APPENDIX D
REVISED REVENUE REQUIREMENT WORKFORM

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Data Input (1)

		Initial Application (2)	Adjustments	Application Update (6)	Adjustments	Per Board Decision
1	**Rate Base**					
	Gross Fixed Assets (average)	$61,111,953	$15,567	$ 61,127,520		$61,127,520
	Accumulated Depreciation (average)	($31,617,647) (5)	$41,571	($31,576,076)		($31,576,076)
	Allowance for Working Capital:					
	Controllable Expenses	$6,999,907		$ 6,999,907		$6,999,907
	Cost of Power	$46,574,530	$305,260	$ 46,879,790		$46,879,790
	Working Capital Rate (%)	7.50% (9)		7.50% (9)		7.50% (9)
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$9,049,877	($15,141)	$9,034,736		
	Distribution Revenue at Proposed Rates	$10,106,284	($227,408)	$9,878,876		
	Other Revenue:					
	Specific Service Charges	$189,829	$0	$189,829		
	Late Payment Charges	$73,781	$0	$73,781		
	Other Distribution Revenue	$252,847	$84	$252,931		
	Other Income and Deductions	$13,593	$0	$13,593		
	Total Revenue Offsets	$530,050 (7)	$84	$530,134		
	Operating Expenses:					
	OM+A Expenses	$6,999,907		$ 6,999,907		$6,999,907
	Depreciation/Amortization	$1,429,600	($12,821)	$ 1,416,779		$1,416,779
	Property taxes					
	Other expenses					
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($876,937) (3)		($857,136)		
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$74,069		$65,497		
	Income taxes (grossed up)	$100,774		$89,112		
	Federal tax (%)	15.00%		15.00%		
	Provincial tax (%)	11.50%		11.50%		
	Income Tax Credits	$20,000		$20,000		
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%		56.0%		
	Short-term debt Capitalization Ratio (%)	4.0% (8)		4.0% (8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%		40.0%		
	Prefered Shares Capitalization Ratio (%)					
		100.0%		100.0%		
	Cost of Capital					
	Long-term debt Cost Rate (%)	4.54%		3.72%		
	Short-term debt Cost Rate (%)	1.65%		1.76%		
	Common Equity Cost Rate (%)	9.19%		8.78%		
	Prefered Shares Cost Rate (%)					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$61,111,953	$15,567	$61,127,520	$ -	$61,127,520
2	Accumulated Depreciation (average)	(2)	($31,617,647)	$41,571	($31,576,076)	$ -	($31,576,076)
3	Net Fixed Assets (average)	(2)	$29,494,306	$57,138	$29,551,444	$ -	$29,551,444
4	Allowance for Working Capital	(1)	$4,018,083	$22,895	$4,040,977	$ -	$4,040,977
5	**Total Rate Base**		$33,512,389	$80,033	$33,592,421	$ -	$33,592,421

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$6,999,907	$ -	$6,999,907	$ -	$6,999,907
7	Cost of Power		$46,574,530	$305,260	$46,879,790	$ -	$46,879,790
8	Working Capital Base		$53,574,437	$305,260	$53,879,697	$ -	$53,879,697
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$4,018,083	$22,895	$4,040,977	$ -	$4,040,977

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2017 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$10,106,284	($227,408)	$9,878,876	$ -	$9,878,876
2	Other Revenue	(1)	$530,050	$84	$530,134	$ -	$530,134
3	Total Operating Revenues		$10,636,334	($227,324)	$10,409,010	$ -	$10,409,010
	Operating Expenses:						
4	OM+A Expenses		$6,999,907	$ -	$6,999,907	$ -	$6,999,907
5	Depreciation/Amortization		$1,429,600	($12,821)	$1,416,779	$ -	$1,416,779
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$8,429,507	($12,821)	$8,416,686	$ -	$8,416,686
10	Deemed Interest Expense		$874,137	($150,691)	$723,446	$152,778	$876,225
11	Total Expenses (lines 9 to 10)		$9,303,644	($163,512)	$9,140,132	$152,778	$9,292,911
12	**Utility income before income taxes**		$1,332,690	($63,812)	$1,268,878	($152,778)	$1,116,099
13	Income taxes (grossed-up)		$100,774	($11,663)	$89,112	$ -	$89,112
14	**Utility net income**		$1,231,916	($52,150)	$1,179,766	($152,778)	$1,026,988

Notes

Other Revenues / Revenue Offsets

Note		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$189,829	$ -	$189,829		$189,829
	Late Payment Charges	$73,781	$ -	$73,781		$73,781
	Other Distribution Revenue	$252,847	$84	$252,931		$252,931
	Other Income and Deductions	$13,593	$ -	$13,593		$13,593
	Total Revenue Offsets	$530,050	$84	$530,134	$ -	$530,134

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$1,231,915	$1,179,766	$1,234,857
2	Adjustments required to arrive at taxable utility income	($876,937)	($857,136)	($857,136)
3	Taxable income	$354,978	$322,630	$377,721
	Calculation of Utility income Taxes			
4	Income taxes	$74,069	$65,497	$65,497
6	Total taxes	$74,069	$65,497	$65,497
7	Gross-up of Income Taxes	$26,705	$23,615	$23,615
8	Grossed-up Income Taxes	$100,774	$89,112	$89,112
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$100,774	$89,112	$89,112
10	Other tax Credits	$20,000	$20,000	$20,000
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$18,766,938	4.54%	$852,019
2	Short-term Debt	4.00%	$1,340,496	1.65%	$22,118
3	**Total Debt**	60.00%	$20,107,433	4.35%	$874,137
	Equity				
4	Common Equity	40.00%	$13,404,956	9.19%	$1,231,915
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$13,404,956	9.19%	$1,231,915
7	**Total**	100.00%	$33,512,389	6.28%	$2,106,053
		Application Update			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$18,811,756	3.72%	$699,797
2	Short-term Debt	4.00%	$1,343,697	1.76%	$23,649
3	**Total Debt**	60.00%	$20,155,453	3.59%	$723,446
	Equity				
4	Common Equity	40.00%	$13,436,969	8.78%	$1,179,766
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$13,436,969	8.78%	$1,179,766
7	**Total**	100.00%	$33,592,421	5.67%	$1,903,212
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$18,811,756	4.54%	$854,054
9	Short-term Debt	4.00%	$1,343,697	1.65%	$22,171
10	**Total Debt**	60.00%	$20,155,453	4.35%	$876,225
	Equity				
11	Common Equity	40.00%	$13,436,969	9.19%	$1,234,857
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$13,436,969	9.19%	$1,234,857
14	**Total**	100.00%	$33,592,421	6.28%	$2,111,082

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Application Update		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$1,327,391		$1,054,460		$1,337,276
2	Distribution Revenue	$9,049,877	$8,778,893	$9,034,736	$8,824,416	$9,034,736	$8,541,600
3	Other Operating Revenue Offsets - net	$530,050	$530,050	$530,134	$530,134	$530,134	$530,134
4	**Total Revenue**	$9,579,927	$10,636,334	$9,564,870	$10,409,010	$9,564,870	$10,409,010
5	Operating Expenses	$8,429,507	$8,429,507	$8,416,686	$8,416,686	$8,416,686	$8,416,686
6	Deemed Interest Expense	$874,137	$874,137	$723,446	$723,446	$876,225	$876,225
8	**Total Cost and Expenses**	$9,303,644	$9,303,644	$9,140,132	$9,140,132	$9,292,911	$9,292,911
9	**Utility Income Before Income Taxes**	$276,283	$1,332,690	$424,738	$1,268,878	$271,959	$1,116,099
10	Tax Adjustments to Accounting Income per 2013 PILs model	($876,937)	($876,937)	($857,136)	($857,136)	($857,136)	($857,136)
11	**Taxable Income**	($600,654)	$455,753	($432,398)	$411,742	($585,177)	$258,963
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$120,775	$ -	$109,112	$ -	$68,625
14	**Income Tax Credits**	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
15	**Utility Net Income**	$256,283	$1,231,916	$404,738	$1,179,766	$251,959	$1,026,988
16	**Utility Rate Base**	$33,512,389	$33,512,389	$33,592,421	$33,592,421	$33,592,421	$33,592,421
17	Deemed Equity Portion of Rate Base	$13,404,956	$13,404,956	$13,436,969	$13,436,969	$13,436,969	$13,436,969
18	Income/(Equity Portion of Rate Base)	1.91%	9.19%	3.01%	8.78%	1.88%	7.64%
19	Target Return - Equity on Rate Base	9.19%	9.19%	8.78%	8.78%	9.19%	9.19%
20	Deficiency/Sufficiency in Return on Equity	-7.28%	0.00%	-5.77%	0.00%	-7.31%	-1.55%
21	Indicated Rate of Return	3.37%	6.28%	3.36%	5.67%	3.36%	5.67%
22	Requested Rate of Return on Rate Base	6.28%	6.28%	5.67%	5.67%	6.28%	6.28%
23	Deficiency/Sufficiency in Rate of Return	-2.91%	0.00%	-2.31%	0.00%	-2.93%	-0.62%
24	Target Return on Equity	$1,231,915	$1,231,915	$1,179,766	$1,179,766	$1,234,857	$1,234,857
25	Revenue Deficiency/(Sufficiency)	$975,633	$0	$775,028	$0	$982,898	($207,870)
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,327,391 (1)		$1,054,460 (1)		$1,337,276 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$6,999,907		$6,999,907		$6,999,907	
2	Amortization/Depreciation	$1,429,600		$1,416,779		$1,416,779	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$100,774		$89,112		$89,112	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$874,137		$723,446		$876,225	
	Return on Deemed Equity	$1,231,915		$1,179,766		$1,234,857	
8	**Service Revenue Requirement (before Revenues)**	$10,636,334		$10,409,010		$10,616,880	
9	Revenue Offsets	$530,050		$530,134		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$10,106,284		$9,878,876		$10,616,880	
11	Distribution revenue	$10,106,284		$9,878,876		$9,878,876	
12	Other revenue	$530,050		$530,134		$530,134	
13	**Total revenue**	$10,636,334		$10,409,010		$10,409,010	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	$0	(1)	($207,870)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$10,636,334	$10,409,010	($0)	$10,616,880	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$1,327,391	$1,054,460	($0)	$1,337,276	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$10,106,284	$9,878,876	($0)	$10,616,880	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,056,407	$844,140	($0)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Application Update

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential	21,042	161,051,510		21,025	158,180,520				
2	General Service Less Than 50 kW	1,783	54,658,680		1,777	51,585,867				
3	General Service 50 to 4,999 kW	149	128,665,764	362,937	154	134,086,770	377,726			
4	Unmetered Scattered Load	257	944,313		261	963,825				
5	Sentinel Lighting	515	753,964	2,077	509	749,437	2,061			
6	Street Lighting	6,853	1,282,067	3,560	6,856	1,286,433	3,582			
7	Large Use									
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**347,356,298**							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Application Update***

A) ***Allocated Costs***

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
	From Sheet 10. Load Forecast				
1	Residential	$ 5,998,831	64.57%	$ 7,027,539	67.51%
2	General Service Less Than 50 kW	$ 1,118,010	12.03%	$ 1,264,897	12.15%
3	General Service 50 to 4,999 kW	$ 1,806,382	19.44%	$ 1,968,539	18.91%
4	Unmetered Scattered Load	$ 38,984	0.42%	$ 35,064	0.34%
5	Sentinel Lighting	$ 39,282	0.42%	$ 52,280	0.50%
6	Street Lighting	$ 187,006	2.01%	$ 60,691	0.58%
7	Large Use	$ 101,544	1.09%		
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 9,290,039	100.00%	$ **10,409,010**	100.00%
			Service Revenue Requirement (from Sheet 9)	$ **10,409,009.78**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 6,394,155	$ 6,991,578	$ 6,991,578	$ 369,993
2	General Service Less Than 50 kW	$ 1,056,712	$ 1,155,443	$ 1,155,443	$ 59,364
3	General Service 50 to 4,999 kW	$ 1,316,365	$ 1,439,357	$ 1,591,660	$ 81,627
4	Unmetered Scattered Load	$ 45,027	$ 49,234	$ 39,625	$ 2,452
5	Sentinel Lighting	$ 28,840	$ 31,535	$ 40,488	$ 3,950
6	Street Lighting	$ 193,638	$ 211,728	$ 60,081	$ 12,748
7	Large Use				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 9,034,737	$ 9,878,875	$ 9,878,875	$ 530,134

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	106.50%	104.75%	104.75%	85 - 115
2	General Service Less Than 50 kW	96.10%	96.04%	96.04%	80 - 120
3	General Service 50 to 4,999 kW	80.00%	77.26%	85.00%	80 - 120
4	Unmetered Scattered Load	106.50%	147.40%	120.00%	80 - 120
5	Sentinel Lighting	106.50%	67.87%	85.00%	80 - 120
6	Street Lighting	89.30%	369.87%	120.00%	80 - 120
7	Large Use				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2017	2018	2019	
1	Residential	104.75%	104.75%	104.75%	85 - 115
2	General Service Less Than 50 kW	96.04%	96.04%	96.04%	80 - 120
3	General Service 50 to 4,999 kW	85.00%	85.00%	85.00%	80 - 120
4	Unmetered Scattered Load	120.00%	120.00%	120.00%	80 - 120
5	Sentinel Lighting	85.00%	85.00%	85.00%	80 - 120
6	Street Lighting	120.00%	120.00%	120.00%	80 - 120
7	Large Use				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	21,025
kWh	158,180,520

Proposed Residential Class Specific Revenue Requirement[1]	$ 6,991,578.00

Residential Base Rates on Current Tariff		
Monthly Fixed Charge ($)	$	18.76
Distribution Volumetric Rate ($/kWh)	$	0.0105

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	18.76	21,025	$ 4,733,148.00	74.02%
Variable	0.0105	158,180,520	$ 1,660,895.46	25.98%
TOTAL	-	-	$ 6,394,043.46	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	3

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 5,175,468.96	20.51	$ 5,174,673.00
Variable	$ 1,816,109.04	0.0115	$ 1,819,075.98
TOTAL	$ 6,991,578.00	-	$ 6,993,748.98

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	82.68%	$ 5,780,838.64	$ 22.91	$ 5,780,193.00
Variable	17.32%	$ 1,210,739.36	$ 0.0077	$ 1,217,990.00
TOTAL	-	$ 6,991,578.00	-	$ 6,998,183.00

Checks[3]	
Change in Fixed Rate	$ 2.40
Difference Between Revenues @ Proposed Rates and Class Specific	$6,605.00 0.09%

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Application Update*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)
1	Residential	kWh	21,025	158,180,520	-	$ 6,991,578	$ 5,780,839	$ 1,210,739	82.68%	17.32%	
2	General Service Less Than 50 kW	kWh	1,777	51,585,867	-	$ 1,155,443	$ 665,965	$ 489,478	57.64%	42.36%	$ 10,325
3	General Service 50 to 4,999 kW	kW	154	134,086,770	377,726	$ 1,591,660	$ 631,175	$ 960,485	39.66%	60.34%	$ 127,028
4	Unmetered Scattered Load	kWh	261	963,825	-	$ 39,625	$ 32,939	$ 6,686	83.13%	16.87%	
5	Sentinel Lighting	kW	509	749,437	2,061	$ 40,488	$ 23,101	$ 17,387	57.06%	42.94%	
6	Street Lighting	kW	6,856	1,286,433	3,582	$ 60,081	$ 50,840	$ 9,241	84.62%	15.38%	
7	Large Use		-	-	-						
8			-	-	-						
9			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
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#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						

Total Transformer Ownership Allowance: $ 137,353

	Distribution Rates					Revenue Reconciliation		
	Monthly Service Charge		Volumetric Rate					
	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	$22.91	2	$0.0077	/kWh	4	$ 5,780,193.00	$ 1,217,990.0040	$ 6,998,183.00
2	$31.23		$0.0097	/kWh		$ 665,948.52	$ 500,382.9099	$ 1,156,006.43
3	$341.55		$2.8791	/kW		$ 631,184.40	$ 1,087,510.9266	$ 1,591,667.33
4	$10.52		$0.0069	/kWh		$ 32,948.64	$ 6,650.3925	$ 39,599.03
5	$3.78		$8.4360	/kW		$ 23,088.24	$ 17,386.5960	$ 40,474.84
6	$0.62		$2.5797	/kW		$ 51,008.64	$ 9,240.4854	$ 60,249.13
7						$ -	$ -	$ -
8						$ -	$ -	$ -
9						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
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#						$ -	$ -	$ -
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#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -

Rates recover revenue requirement

Total Distribution Revenues	$ 9,886,179.76
Base Revenue Requirement	$ 9,878,875.78
Difference	$ 7,303.98
% Difference	0.074%

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 2,106,053	6.28%	$ 33,512,389	$ 53,574,437	$ 4,018,083	$ 1,429,600	$ 100,774	$ 6,999,907	$ 10,636,334	$ 530,050	$ 10,106,284	$ 1,327,391
Responses to Interrogatories	Grossed Revenue Deficiency not correct in the model.	$ 1,903,212	5.67%	$ 33,592,421	$ 53,879,697	$ 4,040,977	$ 1,416,779	$ 89,112	$ 6,999,907	$ 10,409,010	$ 530,134	$ 9,878,876	$ 844,140
	Change	-$ 202,841	-0.61%	$ 80,032	$ 305,260	$ 22,894	-$ 12,821	-$ 11,662	$ -	-$ 227,324	$ 84	-$ 227,408	-$ 483,251

APPENDIX E
REVISED COST ALLOCATION STUDY

Ontario Energy Board

2017 Cost Allocation Model

EB-2016-0110

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	346,852,851

Total kWs from Load Forecast	383,369

Deficiency/sufficiency (RRWF 8. cell F51)	- 844,140

Miscellaneous Revenue (RRWF 5. cell F48)	530,134

			1	2	3	7	8	9
	ID	**Total**	**Residential**	**GS <50**	**GS >50 to 4999 kW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	346,852,851	158,180,520	51,585,867	134,086,770	1,286,433	749,437	963,825
Forecast kW	**CDEM**	383,369			377,726	3,582	2,061	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		207,389		14,749	192,640			

Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	343,494,830	158,180,520	51,585,867	130,728,749	1,286,433	749,437	963,825
Existing Monthly Charge			$18.76	$29.23	$281.42	$1.99	$2.69	$11.93
Existing Distribution kWh Rate			$0.0105	$0.0086				$0.0079
Existing Distribution kW Rate					$2.4614	$8.3543	$6.0251	
Existing TOA Rate				$0.70	$0.70			
Additional Charges								
Distribution Revenue from Rates		$9,179,908	$6,394,155	$1,067,036	$1,451,213	$193,638	$28,840	$45,027
Transformer Ownership Allowance		$145,172	$0	$10,324	$134,848	$0	$0	$0
Net Class Revenue	**CREV**	$9,034,736	$6,394,155	$1,056,712	$1,316,365	$193,638	$28,840	$45,027

Ontario Energy Board

2017 Cost Allocation Model

EB-2016-0110

Sheet I6.2 Customer Data Worksheet -

			1	2	3	7	8	9
	ID	Total	Residential	GS <50	GS >50 to 4999 kW	Street Light	Sentinel	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$99,570	$75,673	$8,961	$14,935	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$72,853	$45,533	$12,385	$14,789		$146	
Number of Bills	CNB	279,710	252,306	21,327	1,853	12	2,160	2,052
Number of Devices	CDEV					6,856	509	261
Number of Connections (Unmetered)	CCON	4,428				3,658	509	261
Total Number of Customers	CCA	22,957	21,025	1,777	154			
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	23,129	21,025	1,777	154	172		
Line Transformer Customer Base	CCLT	23,091	21,025	1,767	126	172		
Secondary Customer Base	CCS	22,945	21,025	1,775	144			
Weighted - Services	CWCS	22,801	21,025	1,775	-	-	-	-
Weighted Meter -Capital	CWMC	3,073,869	2,463,767	554,672	55,429	-	-	-
Weighted Meter Reading	CWMR	160,143	21,042	7,133	131,968	-	-	-
Weighted Bills	CWNB	287,230	252,306	21,327	9,265	120	2,160	2,052

Bad Debt Data

Historic Year:	2012	86,306	65,592	7,768	12,946			
Historic Year:	2013	150,594	114,452	13,553	22,589			
Historic Year:	2014	61,809	46,975	5,563	9,271			
Three-year average		**99,570**	**75,673**	**8,961**	**14,935**	-	-	-

ario Energy Board

2017 Cost Allocation Model

EB-2016-0110

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS >50 to 4999 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$9,034,736	$6,394,155	$1,056,712	$1,316,365	$193,638	$28,840	$45,027
mi	Miscellaneous Revenue (mi)	$530,134	$369,993	$59,364	$81,627	$12,748	$3,950	$2,452
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$9,564,870	$6,764,147	$1,116,076	$1,397,992	$206,386	$32,791	$47,478
	Factor required to recover deficiency (1 + D)	1.0934						
	Distribution Revenue at Status Quo Rates	$9,878,876	$6,991,578	$1,155,443	$1,439,357	$211,730	$31,535	$49,234
	Miscellaneous Revenue (mi)	$530,134	$369,993	$59,364	$81,627	$12,748	$3,950	$2,452
	Total Revenue at Status Quo Rates	$10,409,010	$7,361,571	$1,214,807	$1,520,984	$224,478	$35,485	$51,685
	Expenses							
di	Distribution Costs (di)	$2,995,390	$1,867,236	$373,410	$709,178	$23,420	$14,200	$7,947
cu	Customer Related Costs (cu)	$1,936,786	$1,637,365	$187,075	$91,291	$583	$10,499	$9,974
ad	General and Administration (ad)	$2,067,731	$1,468,829	$235,051	$335,909	$10,075	$10,356	$7,511
dep	Depreciation and Amortization (dep)	$1,416,779	$869,730	$199,510	$327,142	$10,114	$6,591	$3,692
INPUT	PILs (INPUT)	$89,111	$52,974	$12,070	$22,588	$738	$476	$266
INT	Interest	$723,446	$430,068	$97,987	$183,381	$5,991	$3,862	$2,157
	Total Expenses	$9,229,244	$6,326,202	$1,105,103	$1,669,489	$50,921	$45,983	$31,546
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,179,766	$701,337	$159,794	$299,050	$9,770	$6,297	$3,518
	Revenue Requirement (includes NI)	$10,409,010	$7,027,539	$1,264,897	$1,968,539	$60,691	$52,280	$35,064
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$54,132,558	$31,879,948	$7,360,042	$13,991,828	$447,390	$290,897	$162,454
gp	General Plant - Gross	$7,725,897	$4,591,620	$1,045,943	$1,959,705	$63,981	$41,485	$23,163
accum dep	Accumulated Depreciation	($31,576,075)	($18,474,530)	($4,306,415)	($8,270,011)	($260,590)	($169,728)	($94,800)
co	Capital Contribution	($730,936)	($430,060)	($97,179)	($190,182)	($6,064)	($4,806)	($2,645)
	Total Net Plant	$29,551,444	$17,566,977	$4,002,391	$7,491,341	$244,717	$157,847	$88,172
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$46,879,789	$21,634,414	$7,015,292	$17,787,994	$203,482	$105,732	$132,875
	OM&A Expenses	$6,999,907	$4,973,430	$795,536	$1,136,377	$34,079	$35,054	$25,431
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$53,879,696*	*$26,607,844*	*$7,810,828*	*$18,924,371*	*$237,561*	*$140,786*	*$158,306*
	Working Capital	$4,040,977	$1,995,588	$585,812	$1,419,328	$17,817	$10,559	$11,873
	Total Rate Base	$33,592,421	$19,562,565	$4,588,203	$8,910,668	$262,534	$168,406	$100,045
		Rate Base Input equals Output						
	Equity Component of Rate Base	$13,436,968	$7,825,026	$1,835,281	$3,564,267	$105,013	$67,362	$40,018
	Net Income on Allocated Assets	$1,179,766	$1,035,368	$109,704	($148,505)	$173,557	($10,497)	$20,139

ario Energy Board

2017 Cost Allocation Model

EB-2016-0110

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

	Total	1 Residential	2 GS <50	3 GS >50 to 4999 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Rate Base Assets							
Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
Net Income	$1,179,766	$1,035,368	$109,704	($148,505)	$173,557	($10,497)	$20,139
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	100.00%	104.75%	96.04%	77.26%	369.87%	67.88%	147.40%
EXISTING REVENUE MINUS ALLOCATED COSTS	($844,140)	($263,392)	($148,821)	($570,547)	$145,695	($19,490)	$12,415
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$334,031	($50,090)	($447,555)	$163,787	($16,795)	$16,622
RETURN ON EQUITY COMPONENT OF RATE BASE	8.78%	13.23%	5.98%	-4.17%	165.27%	-15.58%	50.33%

Ontario Energy Board

2017 Cost Allocation Model

EB-2016-0110

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	GS <50	GS >50 to 4999 kW	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$6.79	$10.16	$33.16	$0.01	$1.64	$3.08
Customer Unit Cost per month - Directly Related	$9.44	$13.91	$49.97	$0.02	$2.34	$4.38
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$16.94	$21.61	$68.19	$0.95	$8.49	$8.28
Existing Approved Fixed Charge	$18.76	$29.23	$281.42	$1.99	$2.69	$11.93

APPENDIX F
REVISED 2017 PILS WORKFORM

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Version 1.02

Utility Name	Welland Hydro-Electric System Corp.
Assigned EB Number	EB-2016-0110
Name and Title	Wayne Armstrong - Director of Finance & Chief Operating Officer
Phone Number	905-732-1381 Ext 234
Email Address	warmstrong@wellandhydro.com
Date	March 20, 2017
Last COS Re-based Year	2013

Note: Drop-down lists are shaded blue; Input cells are shaded green.

Instructions

Purpose
The purpose of this workbook is to calculate the estimated Payment in Lieu of Taxes (PILs) for the Test Year. The calculation of PILs for the Test Year is on tab T0 and is based on the inputs on the other tabs.

Tab S Summary is a summary of the amounts to be transferred to the Data Input Sheet of the Revenue Requirement Workform.

Methodology
To calculate the PILs for the Test Year:

1) input the balances from the income tax return of the Historical Year in tabs H1 to H13.
2) input the balances for the subsequent two (2) years (the Bridge Year and the Test Year).
Inputs should include:
- non-deductible expenses (Schedule 1 - B1 and T1)
- capital additions (Schedule 8 - B8 and T8)
- cumulative eligible expenditures (Schedule 10 - B10 and T10)
- non-deductible reserves (Schedule 13 - B13 and T13)

3) make any other adjustments and inputs required so that the PILs amount calculated for the Test Year on tab T0 is reasonable.

Other Notes
Tabs H1 to H13 relate to the Historical Year.
Tabs B1 to B13 relate to the Bridge Year.
Tabs T1 to T13 relate to the Test Year.

The amounts on tabs H1 to H13 should agree to the tax return filed with the Canada Revenue Agency. Any CRA audit adjustments or corrections should also be reflected.

It is assumed the net income before tax for the Test Year is equal to the Return on Equity. Return on Equity is calculated on tab A.

On tab "A. Data Input Sheet", input the "Rate Base" amount and "Return on Rate Base" amounts.

For the 2017 Application, the "Test Year" is 2017, the "Historical Year" is 2015, and the "Bridge Year" is 2016.

Updated: June 14, 2016

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

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No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference	
Adjustments required to arrive at taxable income	as below	**-857,136**
Test Year - Payments in Lieu of Taxes (PILs)	T0	**65,497**
Test Year - Grossed-up PILs	T0	**89,111**
Effective Federal Tax Rate	T0	**15.0%**
Effective Ontario Tax Rate	T0	**11.5%**

Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	1,179,766	
Taxable Income	T1	322,630	
Difference	calculated	-857,136	as above

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 33,592,421**	**$ 35,003,118**	

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	$ 1,343,697	W = S * T	
Deemed Long Term Debt %	56.00%	U	$ 18,811,756	X = S * U	
Deemed Equity %	40.00%	V	$ 13,436,968	Y = S * V	
Short Term Interest Rate	1.76%	Z	$ 23,649	AC = W * Z	
Long Term Interest	3.72%	AA	$ 699,797	AD = X * AA	
Return on Equity (Regulatory Income)	8.78%	AB	**$ 1,179,766**	AE = Y * AB	T1
Return on Rate Base			**$ 1,903,212**	AF = AC + AD + AE	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Tax Rates **Federal & Provincial** **As of May 16, 2016**	**Effective January 1, 2012**	**Effective January 1, 2013**	**Effective January 1, 2014**	**Effective January 1, 2015**	**Effective January 1, 2016**	**Effective January 1, 2017**
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%	10.50%	10.50%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	$ 739,528	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	**B**			
	Federal tax rate (Maximum 15%)	15.00%	**C**			
	Combined tax rate (Maximum 26.5%)				26.50%	**D = B+C**
Total Income Taxes					**$ 195,975**	**E = A * D**
Investment Tax Credits					$ 26,521	**F**
Miscellaneous Tax Credits						**G**
Total Tax Credits					**$ 26,521**	**H = F + G**
Corporate PILs/Income Tax Provision for Historical Year					**$ 169,454**	**I = E - H**

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	1,023,515		1,023,515
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	1,327,966		1,327,966
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112	2,841		2,841
Taxable Capital Gains	113	3,208		3,208
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	2,774		2,774
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125	1,286,645		1,286,645
Reserves from financial statements- balance at end of year	126	3,690,671		3,690,671
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
Apprenticeship Tax Credits Ontario $20,000 plus Federal $6,521	294	26,521		26,521
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Closing Adj Expenditures in Regulatory Assets		1,443,266		1,443,266
Retirement Proceeds 18 (1)(b) Line 290		35,287		35,287

				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**7,819,179**	**0**	**7,819,179**
Deductions:				
Gain on disposal of assets per financial statements	401	184		184
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	2,150,855	15,279	2,135,576
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	73,963		73,963
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413	2,107,374		2,107,374
Reserves from financial statements - balance at beginning of year	414	2,891,009		2,891,009
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Opening Adj Expenditures in Regulatory Assets		895,060		895,060
				0
				0
				0
				0
				0
				0
Total Deductions		**8,118,445**	**15,279**	**8,103,166**
Net Income for Tax Purposes		**724,249**	**-15,279**	**739,528**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**724,249**	**-15,279**	**739,528**

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	14,442,257		14,442,257
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	506,830		506,830
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	198,444		198,444
10	Computer Hardware/ Vehicles	354,608		354,608
10.1	Certain Automobiles			0
12	Computer Software	37,021		37,021
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	11,052		11,052
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment	15,279		15,279
45	Computers & Systems Software acq'd post Mar 22/04	184		184
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	14,119,428		14,119,428
50	Data Network Infrastructure Equipment - post Mar 2007	103,260		103,260
52	Computer Hardware and system software			0
95	CWIP			0
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	29,788,363	0	29,788,363

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Income Tax/PILs Workform for 2017 Filer

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				1,056,614
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				1,056,614
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				1,056,614
Current Year Deduction		1,056,614	x 7% =	73,963
Cumulative Eligible Capital - Closing Balance				982,651

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)	124,767		124,767
Reserve for goods and services not delivered ss. 20(1)(m)	1,982,607		1,982,607
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**2,107,374**	**0**	**2,107,374**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:	1,583,297		1,583,297
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**1,583,297**	**0**	**1,583,297**

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

PILS Tax Provision - Bridge Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate		Reference	Wires Only	
Regulatory Taxable Income						B1	$ 142,616	A
Ontario (Max 11.5%)	11.5%	11.5%	$ 16,401	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	$ 21,392	15.0%	C			
Combined effective tax rate (Max 26.5%)							26.50%	D = B + C
Total Income Taxes							$ 37,793	E = A * D
Investment Tax Credits							$ 20,000	F
Miscellaneous Tax Credits								G
Total Tax Credits							$ 20,000	H = F + G
Corporate PILs/Income Tax Provision for Bridge Year							$ 17,793	I = E - H

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	A		850,604
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		1,379,863
Amortization of intangible assets	106		19,253
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		15,275
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		3,000
Non-deductible meals and entertainment expense	121		
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	2,107,374
Reserves from financial statements- balance at end of year	126	B13	3,938,195
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
Apprentice Tax Credits	294		20,000
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Closing Adj Expenditures in Regulatory Assets			1,561,604
Retirement Proceeds 18 (1)(b) Line 290			13,784
Total Additions			**9,058,348**

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Income Tax/PILs Workform for 2017 Filers

Adjusted Taxable Income - Bridge Year

Deductions:			
Gain on disposal of assets per financial statements	401		7,934
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	2,190,215
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10	405	B10	68,786
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	2,365,465
Reserves from financial statements - balance at beginning of year	414	B13	3,690,671
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Closing Adj Expenditures in Regulatory Assets			1,443,266
Total Deductions		calculated	**9,766,336**
Net Income for Tax Purposes		calculated	**142,616**
Charitable donations from Schedule 2	311		0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320		
Non-capital losses of preceding taxation years from Schedule 4	331	B4	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332		
Limited partnership losses of preceding taxation years from Schedule 4	335		
TAXABLE INCOME		calculated	**142,616**

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Application of Loss Carry Forward to reduce taxable income in Bridge Year		0	
Other Adjustments Add (+) Deduct (-)	B1	0	
Balance available for use in Test Year	calculated	0	
Amount to be used in Bridge Year	B1	0	
Balance available for use post Bridge Year	calculated	0	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Application of Loss Carry Forward to reduce taxable income in Bridge Year			
Other Adjustments Add (+) Deduct (-)			
Balance available for use in Test Year	calculated	0	
Amount to be used in Bridge Year			
Balance available for use post Bridge Year	calculated	0	T4

Income Tax/PILs Workform for 2017 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year
1	Distribution System - post 1987	H8	$ 14,442,257			$ 14,442,257	$ -	$ 14,442,257	4%	$ 577,690		$ 13,864,567
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	H8	$ 506,830			$ 506,830	$ -	$ 506,830	6%	$ 30,410		$ 476,420
2	Distribution System - pre 1988	H8				$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	H8	$ 198,444	$ 97,925		$ 296,369	$ 48,963	$ 247,407	20%	$ 49,481		$ 246,888
10	Computer Hardware/ Vehicles	H8	$ 354,608	$ 598,661	-$ 8,125	$ 945,144	$ 295,268	$ 649,876	30%	$ 194,963		$ 750,181
10.1	Certain Automobiles	H8				$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	H8	$ 37,021	$ 33,537		$ 70,558	$ 16,769	$ 53,790	100%	$ 53,790		$ 16,769
13 1	Lease # 1	H8				$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	H8				$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	H8				$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	H8				$ -	$ -	$ -		$ -		$ -
14	Franchise	H8				$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8	$ 11,052			$ 11,052	$ -	$ 11,052	8%	$ 884		$ 10,168
42	Fibre Optic Cable	H8				$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	H8				$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	H8	$ 15,279			$ 15,279	$ -	$ 15,279	50%	$ 7,640		$ 7,640
45	Computers & Systems Software acq'd post Mar 22/04	H8	$ 184			$ 184	$ -	$ 184	45%	$ 83		$ 101
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8				$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	H8	$ 14,119,428	$ 2,086,324	-$ 5,660	$ 16,200,092	$ 1,040,332	$ 15,159,760	8%	$ 1,212,781		$ 14,987,311
50	Data Network Infrastructure Equipment - post Mar 2007	H8	$ 103,260	$ 20,730		$ 123,990	$ 10,365	$ 113,625	55%	$ 62,494		$ 61,496
52	Computer Hardware and system software	H8				$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	H8				$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
	TOTAL		$ 29,788,363	$ 2,837,177	-$ 13,785	$ 32,611,755	$ 1,411,696	$ 31,200,059		$ 2,190,215	B1	$ 30,421,540

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filer

Schedule 10 CEC - Bridge Year

			Reference	
Cumulative Eligible Capital			H10	982,651
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				982,651
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal		x 3/4 =		0
Cumulative Eligible Capital Balance				982,651
Current Year Deduction		982,651	x 7% =	68,786
Cumulative Eligible Capital - Closing Balance				913,865

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments		Balance for Bridge Year		Change During the Year	Disallowed Expenses
						Additions	Disposals				
Capital Gains Reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	124,767		124,767		152,134	124,767	152,134	T13	27,367	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	1,982,607		1,982,607		2,213,331	1,982,607	2,213,331	T13	230,724	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & Share Issue Expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		2,107,374	0	2,107,374	B1	2,365,465	2,107,374	2,365,465	B1	258,091	0
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General reserve for bad debts	H13	0		0				0	T13	0	
Accrued Employee Future Benefits:	H13	1,583,297		1,583,297		1,572,730	1,583,297	1,572,730	T13	-10,567	
- Medical and Life Insurance	H13	0	2,107,374	2,107,374		2,365,465	2,107,374	2,365,465	T13	258,091	
-Short & Long-term Disability	H13	0		0				0	T13	0	
-Accmulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	0		0				0	T13	0	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		1,583,297	2,107,374	3,690,671	B1	3,938,195	3,690,671	3,938,195	B1	247,524	0

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

PILs Tax Provision - Test Year

								Wires Only	
Regulatory Taxable Income							T1	$ 322,630	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate					
Ontario (Max 11.5%)	11.5%	11.5%	$ 37,102	11.5%	B				
Federal (Max 15%)	15.0%	15.0%	$ 48,394	15.0%	C				
Combined effective tax rate (Max 26.5%)								26.50%	D = B + C
Total Income Taxes								**$ 85,497**	E = A * D
Investment Tax Credits								$ 20,000	F
Miscellaneous Tax Credits									G
Total Tax Credits								**$ 20,000**	H = F + G
Corporate PILs/Income Tax Provision for Test Year								**$ 65,497**	I = E - H S. Su
Corporate PILs/Income Tax Provision Gross Up [1]						73.50%	J = 1-D	**$ 23,615**	K = I/J-I
Income Tax (grossed-up)								**$ 89,111**	L = K + I S. Su

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2017 File

Taxable Income - Test Year

		Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	1,179,766

	T2 S1 line #		
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		1,416,779
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		12,900
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		3,000
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	2,365,465
Reserves from financial statements- balance at end of year	126	T13	3,935,120
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions: (please explain in detail the nature of the item)			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
Apprentice Tax Credits	294		20,000
	295		
	296		
	297		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			

Total Additions			**7,753,264**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	2,229,870
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10 CEC	405	T10	63,971
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	2,365,465
Reserves from financial statements - balance at beginning of year	414	T13	3,938,195
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
	395		
	396		
	397		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**8,597,500**
NET INCOME FOR TAX PURPOSES		calculated	**335,530**
Charitable donations	311		12,900
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	0
Net-capital losses of preceding taxation years (Please show calculation)	332		
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**322,630**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Working Paper Reference**	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year	B4	0		0
				0
Other Adjustments Add (+) Deduct (-)	T1	0		0
Balance available for use in Future Years	calculated	0	0	0
Amount to be used in Test Year	T1	0		0
Balance available for use post Test Year	calculated	0	0	0

Net Capital Loss Carry Forward Deduction		**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year	B4	0		0
				0
Other Adjustments Add (+) Deduct (-)				0
Balance available for use in Future Years	calculated	0	0	0
Amount to be used in Test Year				0
Balance available for use post Test Year	calculated	0	0	0

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 13,864,567			$ 13,864,567	$ -	$ 13,864,567	4%	$ 554,583		$ 13,309,984
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ 476,420	0		$ 476,420	$ -	$ 476,420	6%	$ 28,585		$ 447,835
2	Distribution System - pre 1988	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	B8	$ 246,888	5,000		$ 251,888	$ 2,500	$ 249,388	20%	$ 49,878		$ 202,010
10	Computer Hardware/ Vehicles	B8	$ 750,181	35,000		$ 785,181	$ 17,500	$ 767,681	30%	$ 230,304		$ 554,877
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ 16,769	50,000		$ 66,769	$ 25,000	$ 41,769	100%	$ 41,769		$ 25,000
13 1	Lease # 1	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	B8	$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise	B8	$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	B8	$ 10,168	100,000		$ 110,168	$ 50,000	$ 60,168	8%	$ 4,813		$ 105,354
42	Fibre Optic Cable	B8	$ -			$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	B8	$ 7,640		-7,640	$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	B8	$ 101			$ 101	$ -	$ 101	45%	$ 46		$ 56
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	B8	$ 14,987,311	2,073,986		$ 17,061,297	$ 1,036,993	$ 16,024,304	8%	$ 1,281,944		$ 15,779,353
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ 61,496	15,000		$ 76,496	$ 7,500	$ 68,996	55%	$ 37,948		$ 38,548
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 30,421,540	$ 2,278,986	-$ 7,640	$ 32,692,887	$ 1,139,493	$ 31,553,394		$ 2,229,870	T1	$ 30,463,017

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital			B10	913,865
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				913,865
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				913,865
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		913,865	x 7% =	63,971
Cumulative Eligible Capital - Closing Balance				849,895

Ontario Energy Board

Income Tax/PILs Workform for 2017 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	152,134		152,134		152,134	152,134	152,134		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	2,213,331		2,213,331		2,213,331	2,213,331	2,213,331		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		2,365,465	0	2,365,465	T1	2,365,465	2,365,465	2,365,465	T1	0	0
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	1,572,730		1,572,730		1,569,655	1,572,730	1,569,655		-3,075	
- Medical and Life Insurance	B13	2,365,465		2,365,465		2,365,465	2,365,465	2,365,465		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		3,938,195	0	3,938,195	T1	3,935,120	3,938,195	3,935,120	T1	-3,075	0

APPENDIX G
REVISED CURRENT TARIFF OF RATES & CHARGES

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2017
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0110

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached or semi-detached units, as defined in the local zoning by-law. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	22.91
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0077
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kWh	-0.0008
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018 Applicable for only Non-WMP	$/kWh	-0.0007
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2018 Applicable only for Non-RPP	$/kWh	0.0014
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2017) - effective until April 30, 2018	$	0.09
Rate Rider for Disposition of Account 1575 Deferral/Variance Account (2017) - effective until April 30, 2018	$	0.1478
Rate Rider for Dispostion of LRAM 1568 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kWh	-0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0077
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0060

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0110

Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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EB-2016-0110

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

In addition to the charges specified on page 1 of this tariff of rates and charges, the following credits are to be applied to eligible residential customers.

APPLICATION

The application of the charges are in accordance with the Distribution System Code (Section 9) and subsection 79.2(4) of the Ontario Energy Board Act, 1998.

The application of these charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

In this class:

"Aboriginal person" includes a person who is a First Nations person, a Métis person or an Inuit person;
"account-holder" means a consumer who has an account with a distributor that falls within a residential-rate classification as specified in a rate order made by the Ontario Energy Board under section 78 of the Act, and who lives at the service address to which the account relates for at least six months in a year;
"electricity-intensive medical device" means an oxygen concentrator, a mechanical ventilator, or such other device as may be specified by the Ontario Energy Board;
"household" means the account-holder and any other people living at the accountholder's service address for at least six months in a year, including people other than the account-holder's spouse, children or other relatives;
"household income" means the combined annual after-tax income of all members of a household aged 16 or over;

MONTHLY RATES AND CHARGES

Class A

(a) account-holders with a household income of $28,000 or less living in a household of one or two persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of three persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of five persons; and
(d) account-holders with a household income of between $48,001 and $52,000 living in a household of seven or more persons;
but does not include account-holders in Class E.

OESP Credit	$	(30.00)

Class B

(a) account-holders with a household income of $28,000 or less living in a household of three persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of four persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of six persons;
but does not include account-holders in Class F.

OESP Credit	$	(34.00)

Class C

(a) account-holders with a household income of $28,000 or less living in a household of four persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of five persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of seven or more persons;
but does not include account-holders in Class G.

OESP Credit	$	(38.00)

Class D

(a) account-holders with a household income of $28,000 or less living in a household of five persons; and
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of six persons;
but does not include account-holders in Class H.

OESP Credit	$	(42.00)

Class E

Class E comprises account-holders with a household income and household size described under Class A who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(45.00)

Class F

(a) account-holders with a household income of $28,000 or less living in a household of six or more persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of seven or more persons; or
(c) account-holders with a household income and household size described under Class B who also meet any of the following conditions:

i. the dwelling to which the account relates is heated primarily by electricity;
ii. the account-holder or any member of the account-holder's household is an Aboriginal person; or
iii. the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates

OESP Credit	$	(50.00)

Class G

Class G comprises account-holders with a household income and household size described under Class C who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(55.00)

Class H

Class H comprises account-holders with a household income and household size described under Class D who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person ; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(60.00)

Class I

Class I comprises account-holders with a household income and household size described under paragraphs (a) or (b) of Class F who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(75.00)

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0110

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to commercial buildings taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Commercial buildings are defined as buildings, which are used for purposes other than resident dwellings. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.23
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0097
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kWh	-0.0008
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018 Applicable for only Non-WMP	$/kWh	-0.0007
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2018 Applicable only for Non-RPP	$/kWh	0.0014
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kWh	0.0001
Rate Rider for Disposition of Account 1575 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kWh	0.0002
Rate Rider for Dispostion of LRAM 1568 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011

Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0110

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to commercial buildings whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Commercial buildings are defined as buildings, which are used for purposes other than resident dwellings. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	341.55
Distribution Volumetric Rate	$/kW	2.8791
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kW	-0.2423
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018 Applicable for only Non-WMP	$/kW	-0.2317
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2018 Applicable only for Non-RPP	$/kWh	0.0014
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kW	0.0503
Rate Rider for Disposition of Account 1575 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kW	0.0837
Rate Rider for Dispostion of LRAM 1568 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kW	0.0775
Retail Transmission Rate - Network Service Rate	$/kW	2.3145
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9948

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
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Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	\$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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EB-2016-0110

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Unmetered or flat connections are permitted with the approval of Welland Hydro-Electric System Corp. Engineering Department. Flat rate connects may include, but are not limited to, Traffic Lights, Street Lights, Bus Shelters, and Signs. Energy consumption is determined by information provided by the customer and/or load measurement taken by Welland Hydro-Electric System Corp. following connection of the flat service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	10.52
Distribution Volumetric Rate	$/kWh	0.0069
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kWh	-0.0008
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018 Applicable for only Non-WMP	$/kWh	-0.0007
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2018 Applicable only for Non-RPP	$/kWh	0.0014
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kWh	0.0001
Rate Rider for Disposition of Account 1575 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kWh	0.0002
Rate Rider for Dispostion of LRAM 1568 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kWh	-0.0003
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

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Wholesale Market Service Rate - Not including CBR	\$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	\$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	\$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting not classified as unmetered or street lighting. The consumption for the customer will be based on the calculated connected load times a twelve hour day times the applicable billing period. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.78
Distribution Volumetric Rate	$/kW	8.4360
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kW	-0.2918
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018 Applicable for only Non-WMP	$/kW	-0.2394
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2018 Applicable only for Non-RPP	$/kWh	0.0014
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kW	0.0515
Rate Rider for Disposition of Account 1575 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kW	0.0857
Rate Rider for Dispostion of LRAM 1568 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kW	-0.2295
Retail Transmission Rate - Network Service Rate	$/kW	2.1670
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6448

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021

Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
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STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the Street Lighting system owned by the City of Welland. Welland Hydro-Electric System Corp. provides new installations and maintenance of the street lighting system, as required by the City of Welland. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	0.62
Distribution Volumetric Rate	$/kW	2.5797
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kW	-0.2313
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2018 Applicable for only Non-WMP	$/kW	-0.2364
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2018 Applicable only for Non-RPP	$/kWh	0.0014
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2017) - effective until April 30, 2018	$/kW	0.0508
Rate Rider for Disposition of Account 1575 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kW	0.0847
Rate Rider for Dispostion of LRAM 1568 Deferral/Variance Account (2017) - effective until April 30, 2018	$/kW	-0.2610
Retail Transmission Rate - Network Service Rate	$/kW	2.1623
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6411

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011

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Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	11.25

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.7000)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

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SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge – no disconnection – during regular hours	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect at meter - after regular hours	$	185.00
Install/remove load control device - during regular hours	$	65.00

Other

Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35
Meter upgrade requested by customer plus installation-per month plus installation on a time and material basis	$	10.00

Welland Hydro-Electric System Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0110

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

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LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0476
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0371